UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2019
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _________ to _________

Commission file number: 001-38260

BP Midstream Partners LP

(Exact name of registrant as specified in its charter)

Delaware	**82-1646447**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

501 Westlake Park Boulevard, Houston, Texas 77079
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: **(281) 366-2000**
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Units, Representing Limited Partner Interests	BPMP	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer", "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's common units held by non-affiliates of the registrant as of June 28, 2019, was $739 million, based on the closing price of such units of $15.48 as reported on the New York Stock Exchange on such date. As of February 26, 2020, the registrant had 52,387,740 common units and 52,375,535 subordinated units outstanding.

Documents Incorporated By Reference: None

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K (the “Annual Report”) includes various “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended ("Exchange Act"). All statements other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected cost, prospects, plans and objectives of management, are forward-looking statements.

When used in this Annual Report, you can identify our forward-looking statements by words such as “anticipate,” “believe,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “plan,” “predict,” “project,” “seek,” “target,” “could,” “may,” “should,” “would” or other similar expressions that convey the uncertainty of future events or outcomes, although not all forward-looking statements contain such identifying words. When considering forward-looking statements, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” and other cautionary statements contained in this filing.

We based forward-looking statements on our current expectations and assumptions about future events and currently available information as to the outcome and timing of future events. We caution you that these statements are not guarantees of future performance as they involved assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties we cannot predict. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements.

Forward-looking statements may include statements about:

- The continued ability of BP and any non-affiliate customers to satisfy their obligations under our commercial and other agreements, or otherwise ship volumes on our pipelines, and the impact of lower market prices for crude oil, natural gas, refined products and diluent.
- The volume of crude oil, natural gas, refined products and diluent we transport or store and the prices that we can charge our customers.
- The tariff rates with respect to volumes that we transport through our regulated assets, which rates are subject to review and possible adjustment imposed by federal and state regulators.
- Availability of acquisitions and financing for acquisitions on our expected timing and acceptable terms.
- Changes in revenue we realize under the fixed loss allowance provisions of our fees and tariffs resulting from changes in underlying commodity prices.
- Fluctuations in the prices for crude oil, natural gas, refined products and diluent.
- The level of onshore and offshore production and demand for crude oil, natural gas, refined products and diluent.
- Our ability to successfully integrate recently acquired assets with our own and realize the anticipated benefits of such acquisitions.
- Changes in global economic conditions and the effects of a global economic downturn on the business of BP and the business of its suppliers, customers, business partners and credit lenders.
- Liabilities associated with the risks and operational hazards inherent in transporting and/or storing crude oil, natural gas, refined products and diluent.
- Curtailment of operations or expansion projects due to unexpected leaks or spills; severe weather disruption; riots, strikes, lockouts or other industrial disturbances; or failure of information technology systems due to various causes, including unauthorized access or attack.
- Costs or liabilities associated with federal, state and local laws and regulations relating to environmental protection and safety, including spills, releases and pipeline integrity.
- Costs associated with compliance with evolving environmental laws and regulations on climate change.
- Costs associated with compliance with safety regulations and system maintenance programs, including pipeline integrity management program testing and related repairs.
- Changes in tax status.
- Changes in the cost or availability of third-party vessels, pipelines, rail cars and other means of delivering and transporting crude oil, natural gas, refined products and diluent.
- Direct or indirect effects on our business resulting from actual or threatened terrorist incidents or acts of war.
- Changes in, and availability to us, of the equity and debt capital markets.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

GLOSSARY OF TERMS

As used in this Annual Report, the identified terms have the following meanings:

Barrel	*One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons.*
Bbl	*Barrel.*
BSEE	*Bureau of Safety and Environmental Enforcement.*
BP	*BP p.l.c. and, unless context otherwise requires, its controlled affiliates, other than BP Midstream Partners LP, its subsidiaries and general partner.*
BP2	*BP#2 crude oil pipeline system and related assets.*
BP2 OpCo	*BP Two Pipeline Company LLC, which owns BP2.*
BPA	*BP America Inc.*
BP Holdco	*BP Midstream Partners Holdings LLC.*
BPMP	*BP Midstream Partners LP listed on the New York Stock Exchange.*
BP Pipelines	*BP Pipelines (North America), Inc.*
BP Products	*BP Products North America, Inc.*
Capacity	*A pipeline's individual or aggregate capacity is intended as the capacity for the primary purpose of the pipeline based on our experience and/or calculations. For crude pipeline systems, this is typically the delivery capacity to the final destination (even if the system has segments with differing capacity). For product pipeline systems, this is typically the capacity to transport to one or where appropriate a number of delivery points along the pipeline. Furthermore, note that the capacity of a pipeline can change based on the mix of commodities shipped, the physical characteristics of those commodities, the destination of the commodity, and the operating scenario. Therefore, the capacity stated is subject to change based on future physical modifications, commodity changes, or changes in operating scenarios.*
CERCLA	*Comprehensive Environmental Response, Compensation, and Liability Act.*
Clean Water Act	*Water Pollution Control Act of 1972.*
Common carrier pipeline	*A pipeline engaged in the transportation of crude oil, refined products or natural gas liquids as a common carrier for hire.*
Crude oil	*A mixture of raw hydrocarbons that exists in liquid phase in underground reservoirs.*
Delaware Act	*Delaware Revised Uniform Limited Partnership Act.*
Diamondback	*Diamondback diluent pipeline system and related assets.*
Diamondback OpCo	*BP D-B Pipeline Company LLC, which owns Diamondback.*
Diluent	*A light hydrocarbon mixture which, when blended with heavy crude petroleum, reduces the viscosity of crude to make it more efficient to transport by pipeline.*
DOI	*Department of Interior.*
DOT	*Department of Transportation.*
DRA	*Drag reducing agent.*
EPA	*Environmental Protection Agency.*
EPAct	*Energy Policy Act of 1992.*

Estimated Total Maintenance Spend	*Estimated Total Maintenance Spend is a defined term under our partnership agreement. It is estimated annually (and whenever an event occurs that is likely to result in a material adjustment) by the board of directors of our general partner. It is intended to represent the average quarterly Maintenance Capital Expenditures (as such term is defined below) and maintenance expenses that the Partnership will need to incur over the long term to maintain the operating capacity or operating income of the Partnership and its subsidiaries (including the Partnership's proportionate share of the average quarterly Maintenance Capital Expenditures and maintenance expenses of its subsidiaries that are not wholly owned) existing at the time the estimate is made.*
Expansion capital expenditures	*Expansion capital expenditures is a defined term under our partnership agreement. Expansion capital expenditures are cash expenditures (including transaction expenses) for capital improvements. Expansion capital expenditures do not include maintenance capital expenditures or investment capital expenditures. Expansion capital expenditures do include interest payments (including periodic net payments under related interest rate swap agreements) and related fees paid during the construction period on construction debt. Where cash expenditures are made in part for expansion capital expenditures and in part for other purposes, the general partner determines the allocation between the amounts paid for each.*
FASB	*Financial Accounting Standards Board.*
FERC	*Federal Energy Regulatory Commission.*
Fixed loss allowance or FLA	*An allowance for volume losses due to measurement difference set forth in crude oil product transportation agreements, including long-term transportation agreements and tariffs for crude oil shipments.*
GAAP	*United States generally accepted accounting principles.*
Gal	*Gallons.*
GHG	*Greenhouse gas.*
HCA	*High Consequence Area.*
ICA	*Interstate Commerce Act.*
Investment capital expenditures	*Investment capital expenditures means capital expenditures other than Maintenance capital expenditures and Expansion capital expenditures.*
IPO	*Initial Public Offering of BP Midstream Partners LP.*
IPO Contributed Assets	*100% interest in each BP2 OpCo, River Rouge OpCo and Diamondback OpCo, a 28.5% interest in Mars and a 20% managing interest in Mardi Gras.*
IRS	*Internal Revenue Service.*
kboe	*One thousand barrels of oil equivalent.*
kbpd	*Thousand barrels per day.*
LIBOR	*London Interbank Offered Rate.*
LTIP	*BP Midstream Partners LP 2017 Long-Term Incentive Plan.*
Maintenance capital expenditures	*Maintenance capital expenditures is a defined term under our partnership agreement. Maintenance capital expenditures are cash expenditures (including expenditures for (a) the acquisition (through an asset acquisition, merger, stock acquisition, equity acquisition or other form of investment) by the Partnership or any of its subsidiaries of existing assets or assets under construction, (b) the construction or development of new capital assets by the Partnership or any of its subsidiaries, (c) the replacement, improvement or expansion of existing capital assets by the Partnership or any of its subsidiaries or (d) a capital contribution by the Partnership or any of its subsidiaries to a person that is not a subsidiary in which the Partnership or any of its subsidiaries has, or after such capital contribution will have, directly or indirectly, an equity interest, to fund the Partnership or such subsidiary's share of the cost of the acquisition, construction or development of new, or the replacement, improvement or expansion of existing, capital assets by such person), in each case if and to the extent such acquisition, construction, development, replacement, improvement or expansion is made to maintain, over the long-term, the operating capacity or operating income of the Partnership and its subsidiaries, in the case of clauses (a), (b) and (c), or such person, in the case of clause (d), as the operating capacity or operating income of the Partnership and its subsidiaries or such person, as the case may be, existed immediately prior to such acquisition, construction, development, replacement, improvement, expansion or capital contribution. For purposes of this definition, "long-term" generally refers to a period of not less than twelve months. Maintenance capital expenditures do not include expansion capital expenditures or investment capital expenditures.*
MLP	*Master limited partnership.*
MMscf	*One million standard cubic feet.*
MMscf/d	*One million standard cubic feet per day.*
MVC	*Minimum Volume Commitment.*

NEPA	*National Environmental Policy Act.*
NGA	*Natural Gas Act.*
NYSE	*New York Stock Exchange.*
OCSLA	*Outer Continental Shelf Lands Act.*
OPA-90	*Oil Pollution Act of 1990.*
OSHA	*Occupational Safety and Health Act.*
PHMSA	*Pipeline and Hazardous Materials Safety Administration.*
PPI	*U.S. Producer Price Index.*
Predecessor	*The historical financial results of BP2, River Rouge, and Diamondback.*
RCRA	*Resource Conservation and Recovery Act.*
River Rouge	*Whiting to River Rouge refined products pipeline system and related assets.*
River Rouge OpCo	*BP River Rouge Pipeline Company LLC, which owns River Rouge.*
Refined products	*Hydrocarbon compounds, such as gasoline, diesel fuel, jet fuel and residual fuel, that are produced by a refinery.*
ROFO	*Right of First Offer.*
SEC	*Securities and Exchange Commission.*
Throughput	*The volume of crude oil, refined products, diluent or natural gas transported or passing through a refinery, pipeline, terminal or other facility during a particular period.*
Total Maintenance Spend	*The sum of (a) the maintenance expenses of the IPO: Contributed Assets, (b) the maintenance capital expenditures of the IPO Contributed Assets, excluding any reimbursable maintenance capital expenditures, and (c) our allocable portion of the sum of (1) the maintenance expenses of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures and (2) the maintenance capital expenditures of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures, excluding any reimbursable maintenance capital expenditures.*
Wholly Owned Assets	*100% interest in each of BP2 OpCo, River Rouge OpCo and Diamondback OpCo.*
WTI	*West Texas Intermediate.*

BP MIDSTREAM PARTNERS LP

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PART I

Unless otherwise stated or the context otherwise indicates, all references to "we," "our," "us," "Wholly Owned Assets," "Predecessor," or similar expressions for time periods prior to the initial public offering (the "IPO") refer to BP Midstream Partners LP Predecessor, our predecessor for accounting purposes. For time periods subsequent to the IPO, "we," "our," "us," or similar expressions refer to the legal entity BP Midstream Partners LP (the "Partnership"). The term "our Parent" refers to BP Pipelines (North America), Inc. ("BP Pipelines"), any entity that wholly owns BP Pipelines, indirectly or directly, including BP America Inc. and BP p.l.c. ("BP"), and any entity that is wholly owned by the aforementioned entities, excluding BP Midstream Partners LP Predecessor and the Partnership.

Item 1 and 2. BUSINESS AND PROPERTIES

Overview

We are a fee-based, growth-oriented master limited partnership formed by BP Pipelines, an indirect wholly owned subsidiary of BP, to own, operate, develop and acquire pipelines and other midstream assets. Our assets consist of interests in entities that own crude oil, natural gas, refined products and diluent pipelines and refined product terminals serving as key infrastructure for BP and other customers to transport onshore crude oil production to BP's Whiting Refinery and offshore crude oil and natural gas production to key refining markets and trading and distribution hubs. Certain of our assets deliver refined products and diluent from the Whiting Refinery and other U.S. supply hubs to major demand centers.

We own one onshore crude oil pipeline system, one onshore refined products pipeline system, one onshore diluent pipeline system, and interests in five offshore crude oil pipeline systems, one refined product terminalling system and one offshore natural gas pipeline system. Our onshore crude oil pipeline, BP2, indirectly links Canadian crude oil production with BP's Whiting Refinery, the largest refinery in the Midwest. Our River Rouge refined products pipeline system connects the Whiting Refinery to the Detroit refined products market. Our Diamondback diluent pipeline indirectly connects the Whiting Refinery and other diluent supply sources to a third-party pipeline for ultimate delivery to the Canadian oil sands production areas. The offshore crude oil pipeline systems, which include our interests in Mars Oil Pipeline Company, LLC and the pipeline system and related assets owned by such entity (collectively, "Mars"), Ursa Oil Pipeline Company, LLC ("Ursa") and through our ownership in Mardi Gras Transportation System Company, LLC ("Mardi Gras"), Caesar Oil Pipeline Company, LLC and the pipeline system and related assets owned by such entity (collectively, "Caesar"), Proteus Oil Pipeline Company, LLC and the pipeline system and related assets owned by such entity (collectively, "Proteus") and Endymion Oil Pipeline Company, LLC and the pipeline system and related assets owned by such entity (collectively, "Endymion"), link major offshore production areas in the Gulf of Mexico with the Gulf Coast refining and distribution hubs. The offshore natural gas pipeline system, Cleopatra Gas Gathering Company, LLC and the pipeline system and related assets owned by such entity (collectively, "Cleopatra") (also owned through our ownership interest in Mardi Gras), links offshore production areas in the Gulf of Mexico to an offshore pipeline for ultimate delivery to shore. Our ownership interest in the onshore refined products terminal network, KM Phoenix Holdings, LLC ("KM Phoenix"), has 13 refined products storage and terminalling systems located across the United States in markets that are highly strategic to supporting BP's refining, trading and marketing businesses.

We have historically generated substantially all of our revenue under long-term agreements or FERC-regulated generally applicable tariffs by charging fees for the transportation of products through our pipelines. Substantially all of our aggregate revenue on BP2, Diamondback and River Rouge is supported by commercial agreements with BP Products. BP Products has entered into minimum volume commitment agreements with respect to BP2, River Rouge and Diamondback. The dedication agreement and one throughput and deficiency agreement that generate revenue for Diamondback will renew in June 2020 pursuant to their terms for one additional year. The parties have the option to allow the two agreements to renew annually for one additional year by not sending written notice of termination six months prior to the expiration date. The throughput and deficiency agreement that does not have renewal terms will not renew and expires by its terms on December 31, 2020. The Partnership is reviewing its options with respect to that agreement. BP Pipelines also granted us a seven-year ROFO through 2024 with respect to its retained ownership interest in Mardi Gras and all of its interests in midstream pipeline systems and assets related thereto in the contiguous United States and offshore Gulf of Mexico that are owned by BP Pipelines. We refer to these assets collectively as the "Subject Assets". Please see - "Our Commercial Agreements with BP - Right of First Offer" below.

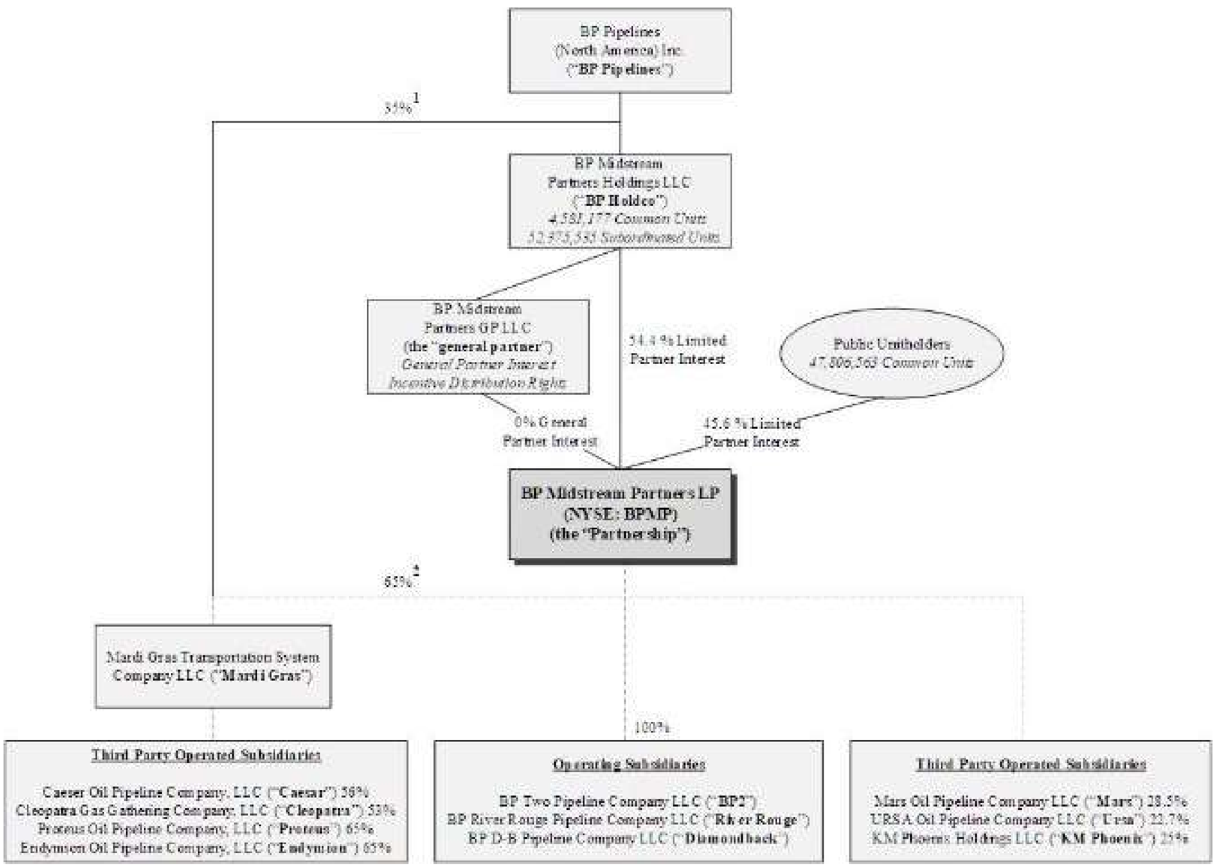
Businesses and Assets

As of December 31, 2019, our businesses and assets consisted of the following:

- BP Two Pipeline Company LLC, which owns the BP#2 crude oil pipeline system ("BP2").
- BP River Rouge Pipeline Company LLC, which owns the Whiting to River Rouge refined products pipeline system ("River Rouge").
- BP D-B Pipeline Company LLC, which owns the Diamondback diluent pipeline system ("Diamondback"). BP2, River Rouge, and Diamondback are in the Midwest region of the United States, and together are referred to as the "Wholly Owned Assets".
- A 28.5% ownership interest in Mars Oil Pipeline Company, LLC ("Mars"), which owns a major corridor crude oil pipeline system in the Gulf of Mexico.
- A 65% managing member interest in Mardi Gras Transportation System Company, LLC ("Mardi Gras"), which holds the following investments in joint ventures located in the Gulf of Mexico:
  - A 56% ownership interest in Caesar Oil Pipeline Company, LLC ("Caesar"),
  - A 53% ownership interest in Cleopatra Gas Gathering Company, LLC ("Cleopatra"),
  - A 65% ownership interest in Proteus Oil Pipeline Company, LLC ("Proteus"), and,
  - A 65% ownership interest in Endymion Oil Pipeline Company, LLC ("Endymion"). Together Endymion, Caesar, Cleopatra and Proteus are referred to as the "Mardi Gras Joint Ventures."
- A 22.7% ownership interest in Ursa Oil Pipeline Company, LLC ("Ursa").
- A 25% ownership interest in KM Phoenix Holdings, LLC ("KM Phoenix").

Organizational Structure

The following simplified diagram depicts our organizational structure as of December 31, 2019.



(1) The remainder of Mardi Gras is held 34% by BP Pipelines and 1% by an affiliate of BP.
(2) The Partnership's interest in Mardi Gras is a managing member interest that provides us with the right to vote Mardi Gras' ownership interest in the Mardi Gras Joint Ventures.

Our Assets and Operations

The table below sets forth certain information regarding our assets as of December 31, 2019:

Entity/Asset	Product Type	Our Ownership Interest		BP Pipelines Retained Ownership Interest	Pipeline Length (Miles)	Capacity (kbpd)(1)		Contract Structure	
BP2	Crude	100.0 %		—	12	475		MVCs/FERC tariff Long term contract	(3)
River Rouge	Refined Products	100.0 %		—	244	80		MVCs/FERC tariff Long term contract	(3)
Diamondback	Diluent	100.0 %		—	42	135		MVCs/FERC tariff/ Long term contract	(3)
Mars	Crude	28.5 %		—	163	400	(2)	FERC and state tariffs/Lease dedication; Portion with guaranteed return	
Mardi Gras(4):		65.0 %	(5)	35.0 %					
Caesar	Crude	36.4 %		19.6 %	115	450		Lease dedication	
Cleopatra	Natural Gas	34.5 %		18.5 %	115	500		Lease dedication	
Proteus	Crude	42.3 %		22.7 %	70	425		Lease dedication	
Endymion	Crude	42.3 %		22.7 %	90	425		Lease dedication	
Ursa	Crude	22.7 %		—	47	150		Joint tariff	
KM Phoenix	Storage	25.0 %		—				Commercial agreements	

(1) The approximate capacity information presented is in kbpd with the exception of the approximate capacity related to Cleopatra gas gathering system, which are presented in MMscf/d. Pipeline capacities are based on current operations and vary depending on the specific products being transported and delivery point, among other factors.

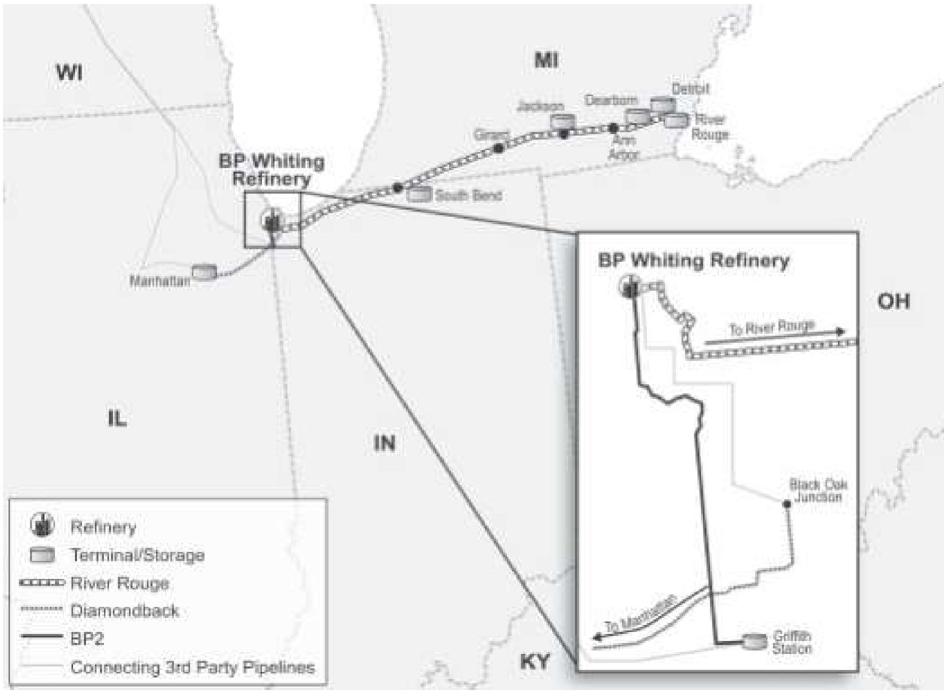
(2) Represents Mars capacity of the approximately 54 mile segment from the connections to Ursa, Medusa and Olympus pipelines at the West Delta 143 platform complex to Fourchon, Louisiana where Mars has a connection with Amberjack pipeline for ultimate delivery to Clovelly, Louisiana. The capacity of the Mars pipeline system ranges from 100 kbpd to 600 kbpd depending on the pipeline segment and the type of crude oil transported.

(3) BP has historically been the sole shipper on BP2 and River Rouge. Substantially all of our revenue on BP2, Diamondback and River Rouge is supported by commercial agreements with BP Products.

(4) Our ownership interest and BP Pipelines' and its affiliates' retained ownership interest in each of Caesar, Cleopatra, Proteus and Endymion represents 65% and 35%, respectively, of the 56%, 53%, 65% and 65% ownership interests in such Mardi Gras Joint Ventures, respectively, held by Mardi Gras.

(5) Our 65% interest in Mardi Gras includes a managing member interest that provides us with the right to vote Mardi Gras' retained ownership interest in the Mardi Gras Joint Ventures.

Onshore Crude Oil, Refined Products and Diluent Pipelines



BP2.

General. BP2 is a crude oil pipeline system consisting of approximately 12 miles of 20- and 22-inch active pipeline and related assets, transporting crude oil for BP from the third-party owned Griffith Terminal in Griffith, Indiana to BP's Whiting Refinery in Whiting, Indiana under FERC-regulated posted tariffs. The Whiting Refinery is the largest refinery in the Midwestern United States with a nameplate capacity of 430 kbpd and has been in operation for more than a century. In 2013, BP finished a multi-billion dollar, multi-year modernization project at the Whiting Refinery that was one of the largest downstream initiatives in the history of BP. The project has modernized the Whiting Refinery by reconfiguring its crude distillation unit and adding advanced hydro-treating, sulphur recovery and coking capacity. With the project's completion, the Whiting Refinery has the flexibility to shift from processing primarily higher-cost sweet crude to discounted heavy crude oil, largely from Canada.

BP is increasing the heavy crude processing capacity at Whiting Refinery from 325 kbpd towards 350 kbpd by year-end 2020. BP has expanded BP2's capacity from approximately 240 kbpd to a current capacity of 475 kbpd to accommodate this growth. BP2 has the ability to ship a wide variety of crude oil types, including heavy, sour, sweet, and synthetic crude. The Whiting Refinery depends on BP2 as its primary source of Canadian heavy crude, and we believe that it has a significant transportation cost advantage over Gulf Coast refiners in accessing this growing supply source. BP also has access to an alternative crude oil pipeline that delivers crude oil to the Whiting Refinery.

Ownership and Operatorship. We own a 100% interest in BP2 and operate the pipeline.

Customers. BP has historically been the sole shipper on BP2.

Contracts. BP2 has historically generated revenue through published tariffs (regulated by the FERC) applied to volumes moved. FERC-approved tariffs may be adjusted annually based on a FERC-published index. The BP2 rate was previously set by settlement and has been subsequently indexed. The tariff applicable to BP2 for crude oil transportation include FLA, which provides additional revenue to offset potential product losses on BP2. We have entered into a commercial agreement with BP Products that includes a minimum volume commitment for BP2 and that supports substantially all of our revenue on BP2. Under this fee-based agreement, we provide transportation services to BP Products, and BP Products commits to pay us for minimum volumes of crude oil through December 31, 2020, regardless of whether such volumes are physically shipped by BP Products through our pipeline during the term of the agreement.

River Rouge.

General. River Rouge is a refined products pipeline system consisting of approximately 244 miles of 12-and 10-inch active pipeline and related assets with a capacity of approximately 80 kbpd transporting refined products for BP from BP's Whiting Refinery to a third party's refined products terminal in River Rouge, Michigan, a major market outlet serving the greater Detroit, Michigan area, as well as third-party terminals along the pipeline. River Rouge is the most direct pipeline route for BP's refined products from the Chicago area to the Detroit market and also serves four other third-party terminals along its pipeline. River Rouge is the sole source of refined products for three of these terminals.

Ownership and Operatorship. We own a 100% interest in and operate River Rouge.

Customers. BP has historically been the sole shipper on River Rouge.

Contracts. River Rouge has historically generated revenue through published tariffs (regulated by the FERC) applied to volumes moved. FERC-approved tariffs may be adjusted annually based on a FERC-published index. The River Rouge rate was previously set based on a cost-of-service method and has been subsequently indexed. We entered into a commercial agreement with BP Products that includes a minimum volume commitment for River Rouge and that supports substantially all of our revenue on River Rouge. Under this fee-based agreement, we provide transportation services to BP Products, and BP Products commits to pay us for minimum volumes of refined products through December 31, 2020, regardless of whether such volumes are physically shipped by BP Products through our pipeline during the term of the agreement.

Diamondback.

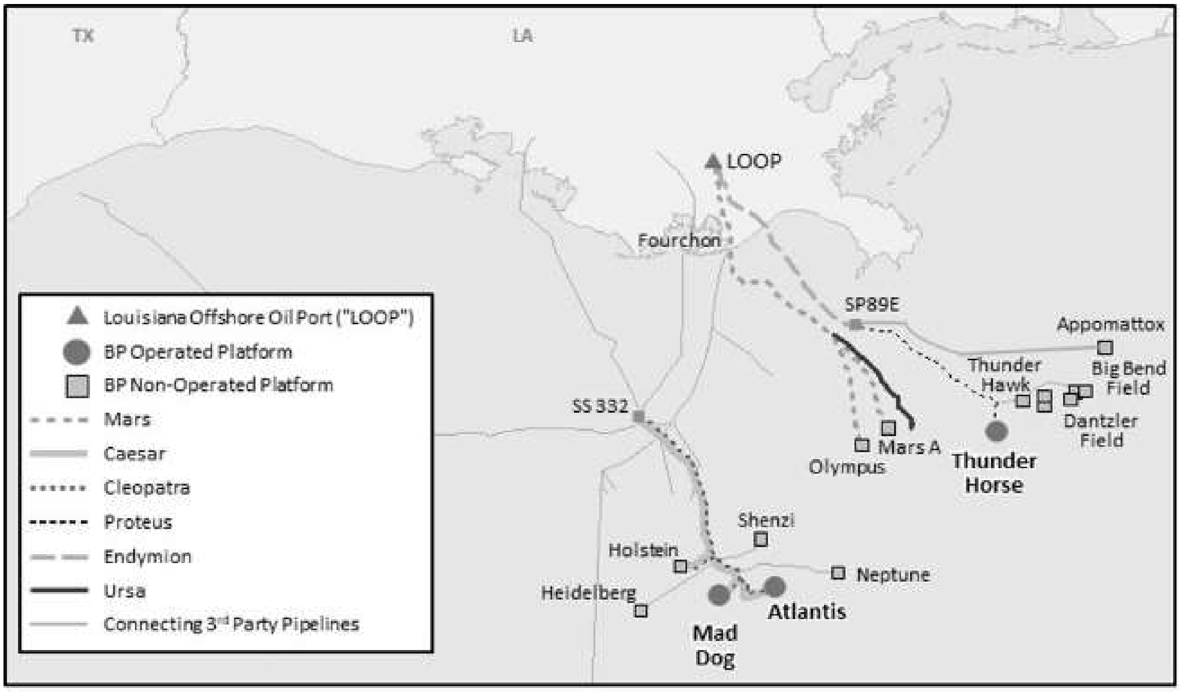
General. Diamondback is a diluent pipeline system consisting of approximately 42 miles of 16-inch active pipeline and related assets with a capacity of approximately 135 kbpd transporting diluent from Diamondback's Black Oak Junction in Gary, Indiana to a third-party owned pipeline in Manhattan, Illinois. The diluent is ultimately transported to Alberta, Canada to be used as a blending agent in the transportation of Canadian heavy crude oil. Black Oak Junction receives diluent from BP's Whiting Refinery via the Wolverine Pipeline, as well as product originating from Gulf Coast and other Midcontinent supply hubs, Midwest producers and refineries. Diamondback is the primary logistics outlet for diluent from BP's Whiting Refinery.

Ownership and Operatorship. We own a 100% interest in Diamondback and operate the pipeline.

Customers. Diamondback's customers include BP as well as multinational integrated oil and gas companies, international and regional trading companies, and Alberta oil producers.

Contracts. Diamondback has historically generated revenue through published tariffs (regulated by the FERC) applied to volumes moved, and certain volumes have been transported pursuant to long-term contracts. FERC-approved tariffs may be adjusted annually based on a FERC-published index. The Diamondback rate was previously set by settlement and has been subsequently indexed. We are a party to commercial agreements with BP Products that includes minimum volume commitments and a dedication agreement for Diamondback. Under these fee based agreements, we provide transportation services to BP Products, and BP Products commits to pay us for a minimum of 8.4 million barrels of diluent in each of the 12 month periods of the agreement's term or approximately 23 kbpd of diluent through June 30, 2021, regardless of whether such volumes are physically shipped by BP Products through our pipeline during the term of the agreement. The parties have the option to allow the agreements to renew annually for one additional year by not sending written notice of termination six months prior to the expiration date. We also have a commercial agreement with BP Products that includes minimum volume commitments for Diamondback. Under this fee-based agreement, we provide transportation services to BP Products, and BP Products commits to pay us for minimum volumes of diluent through December 31, 2020, regardless of whether such volumes are physically shipped by BP Products through our pipeline during the term of the agreement. This agreement does not have renewal terms and expires on December 31, 2020. The Partnership is reviewing its options with respect to that agreement. These agreements support a substantial portion of our revenue on Diamondback.

Offshore Crude Oil and Natural Gas Pipelines.



Mars.

General. Mars is a major corridor crude oil pipeline system in a high-growth area of the Gulf of Mexico, delivering crude oil production received from the Mississippi Canyon area of the Gulf of Mexico, including the Olympus platform, the Mars A platform, the Medusa and Ursa pipelines, and from the Green Canyon and Walker Ridge areas via Amberjack pipeline connection at Fourchon, Louisiana, to shore, terminating in salt dome caverns in Clovelly, Louisiana. The Mars pipeline system is approximately 163 miles in length with capacity, which represents the capacity of the approximately 54 mile segment from the connections to Ursa and Medusa pipelines at the West Delta 143 platform complex to the connection with Amberjack pipeline at Fourchon, Louisiana, of approximately 400 kbpd. The capacity of the Mars pipeline system ranges from 100 kbpd to 600 kbpd depending on the pipeline segment and the type of crude oil transported. Mars is connected to the Louisiana Offshore Oil Port ("LOOP") storage complex, which provides tanker offloading, loading and temporary storage services for the crude oil industry and has access to multiple attractive downstream markets. Mars leases a cavern from LOOP LLC, which provides it with additional operational flexibility and protection for its operations from extreme weather conditions such as hurricanes. As a corridor pipeline, Mars is positioned to allow additional connections from new production platforms and supply pipelines without significant capital expenditures. We expect Mars will be an increasingly important conduit for crude oil produced in the deepwater Gulf of Mexico because it provides the Mississippi Canyon platforms as well as third-party pipelines with access to the LOOP storage complex.

Ownership and Operatorship. We own a 28.5% interest and an affiliate of Shell owns the remaining 71.5% interest in Mars. An affiliate of Shell operates Mars. Under the Mars limited liability company agreement, Mars is managed by a management committee that has full power and authority to manage the entire business and affairs of the Mars pipeline system and oversee the operations of the Mars operator. For as long as there are only two non-affiliated members of Mars, all decisions of the management committee require the vote of at least 51% of the ownership interests in the company, except for certain actions including approving contracts with an affiliate of the operator or approving capital budgets and operating budgets, which require a vote of 100% of the ownership interests, or fundamental actions, including approving capital expenditures above certain amounts, authorizing the borrowing of money on the credit of the company and the dissolution of the company, each of which also requires the vote of members representing 100% of the ownership interests.

The Mars limited liability company agreement provides for cash distributions to the members from time to time, and the management committee may from time to time issue a capital call notice to the members. Under the Mars limited liability company agreement, each member's interest is subject to transfer restrictions, including a right of first refusal in favor of the

other members. Subject to certain exceptions, the Mars limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the vote of a unanimous interest.

Customers. Mars maintains a set of well-established customers, including BP. Mars is connected to several production platforms and the Ursa and Medusa pipeline systems, which tie back to Mars, bringing the production from additional production platforms dedicated to these two pipelines into Mars. Mars also receives significant volume from Amberjack at Fourchon, Louisiana, the terminus of Amberjack pipeline system.

Contracts. Mars generates revenue through published tariffs (regulated by the FERC or the Louisiana Public Service Commission) applied to volumes moved, and certain volumes are transported pursuant to long-term fee-based life-of-lease transportation agreements. Certain fee-based life-of-lease transportation agreements with producers include guaranteed rates-of-return for Mars for an initial period of time where the transportation rate is adjusted annually to achieve a pre-determined rate of return. Subsequent to the expiration of the initial period the rates under the contracts will be no greater than those in effect at the end of the initial period and will continue for the life of the lease with annual adjustments that are no less than zero percent and no greater than the FERC-approved index.

Mardi Gras Joint Ventures

The Partnership, BP Pipelines and the Standard Oil Company, an Ohio corporation ("Standard Oil"), have entered into an amended and restated limited liability company agreement for Mardi Gras that provides us with a 65% managing member interest in Mardi Gras and BP Pipelines and Standard Oil retained a 34% and a 1% interest in Mardi Gras, respectively. Our 65% managing member interest gives us the right to control Mardi Gras, including the right to vote Mardi Gras' ownership interest in each of the Mardi Gras Joint Ventures. Mardi Gras owns a 56% interest in Caesar, a 65% interest in Proteus, a 65% interest in Endymion, and a 53% interest in Cleopatra.

Caesar.

General. Caesar is approximately 115 miles of 24- and 28-inch pipeline with an approximate capacity of 450 kbpd connecting platforms in the Southern Green Canyon area of the Gulf of Mexico with the two connecting carrier pipelines (Cameron Highway and Poseidon) for ultimate transportation to shore. Caesar is designed not only to meet the needs of the original BP-operated Green Canyon area platforms, but also to accommodate new connections for growing production in the area. The Green Canyon area serviced by Caesar is a high-growth area of the Gulf of Mexico and includes the Holstein platform ("Holstein") operated by Occidental Petroleum Corporation ("Oxy"), the BP-operated Mad Dog platform ("Mad Dog"), the BP-operated Atlantis platform ("Atlantis"), the BHP Billiton Ltd ("BHP")-operated Neptune platform ("Neptune") and the Oxy-operated Heidelberg platform ("Heidelberg"). Caesar is expected to transport new volumes from Mad Dog 2 once it comes online, which anticipated to be in 2021. New volumes can enter the pipeline through either subsea tie-backs to currently connected platforms or by connecting to one of three existing and available subsea connections located in the Green Canyon area.

Ownership and Operatorship. We own a 65% managing member interest in Mardi Gras, which owns a 56% interest in Caesar, and unaffiliated third-party investors own the remaining 44%. An affiliate of Shell operates Caesar. Under the Caesar limited liability company agreement, Caesar is managed by a management committee that has full power and authority to manage the entire business and affairs of the Caesar pipeline system and oversee the operations of the Caesar operators. All decisions of the management committees require the vote of two or more members that are not affiliates holding at least 61% of the ownership interests in Caesar, except for certain significant actions, including approving significant capital expenditures, that require the vote of members representing at least 70% of the ownership interests, and certain fundamental actions, including authorizing the merger, consolidation or dissolution of the company, each of which requires the vote of members representing 100% of the ownership interests.

The Caesar limited liability company agreement provides for cash distributions to the members from time to time, and the management committee may from time to time issue capital call notices to the members. Under the Caesar limited liability company agreement, each member's interest is subject to transfer restrictions, including a minimum credit rating requirement for potential transferees. Subject to certain exceptions, the Caesar limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the vote of a unanimous interest.

Customers. Caesar maintains a set of well-established customers, including BP. Caesar is connected to the Mad Dog, Atlantis, Holstein, Neptune and Heidelberg production platforms.

Contracts. Since Caesar is not FERC-regulated under the ICA, in order to ship on Caesar, an oil transportation agreement is negotiated to cover transportation service. Pursuant to any such oil transportation agreement, shippers are generally required to dedicate the production from the fields to Caesar for the life of the applicable lease as a way to ensure the production moves on Caesar.

Cleopatra.

General. Cleopatra is an approximately 115 mile, 16- and 20-inch gas gathering pipeline system with an approximate capacity of 500 MMscf/d and provides gathering and transportation for multiple gas producers in the Southern Green Canyon area of the Gulf of Mexico to the Manta Ray pipeline, which in turn connects to the Nautilus pipeline for ultimate transportation to shore. Cleopatra is designed not only to meet the needs of the original BP-operated Green Canyon area platforms, but also to accommodate new connections for growing production in the area. Cleopatra is currently connected to Holstein, Atlantis and Mad Dog. The system is expected to transport new volumes from Mad Dog 2 once it comes online, which is anticipated to be in 2021. Additionally, Neptune and the BHP-operated Shenzi platform ("Shenzi") have access through third-party pipelines into Cleopatra. The BP operated Atlantis platform is a moored floating facility that can produce up to 200,000 barrels of oil and 180 million cubic feet of gas per day. The BP operated Mad Dog platform is a floating spar facility that can produce up to 80,000 barrels of oil and 60 million cubic feet of gas per day.

Ownership and Operatorship. We own a 65% managing member interest in Mardi Gras, which owns a 53% interest in Cleopatra, and unaffiliated third-party investors own the remaining 47%. An affiliate of Shell operates Cleopatra. Under the Cleopatra limited liability company agreement, Cleopatra is managed by a management committee that has full power and authority to manage the entire business and affairs of the Cleopatra pipeline systems and oversee the operations of the Cleopatra operators. All decisions of the management committee require the vote of two or more members that are not affiliates holding at least 61% of the ownership interests in Cleopatra, except for certain significant actions, including approving significant capital expenditures, that require the vote of members representing at least 70% of the ownership interests, and certain fundamental actions, including authorizing the merger, consolidation or dissolution of the company, each of which requires the vote of members representing 100% of the ownership interests.

The Cleopatra limited liability company agreement provides for cash distributions to the members from time to time, and the management committee may from time to time issue capital call notices to the members. Under the Cleopatra limited liability company agreement, each member's interest is subject to transfer restrictions, including a minimum credit rating requirement for potential transferees. Subject to certain exceptions, the Cleopatra limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the vote of a unanimous interest.

Customers. Cleopatra maintains a set of well-established customers, including BP. Cleopatra is connected to the Mad Dog, Atlantis, Holstein, Neptune and Shenzi production platforms.

Contracts. Since Cleopatra is not FERC-regulated under the NGA, in order to ship on Cleopatra, a gas gathering agreement is negotiated to cover transportation service. Pursuant to any such gas gathering agreement, shippers are generally required to dedicate the production from the fields to Cleopatra for the life of the applicable lease as a way to ensure the production moves on Cleopatra.

Proteus.

General. Proteus is an approximately 70 mile, 24- and 28-inch crude oil pipeline system with an approximate capacity of 425 kbpd and provides transportation into Endymion for multiple crude oil producers in the eastern Gulf of Mexico. The pipeline provides takeaway capacity for the BP-operated Thunder Horse ("Thunder Horse") and Noble Energy-operated Thunder Hawk ("Thunder Hawk") platforms to the Proteus SP 89E Platform ("SP 89E"). Noble's Big Bend and Dantzler fields are connected to the Thunder Hawk platform. An affiliate of Shell built the Mattox pipeline, which is connected to Proteus. Through this upstream connection, Proteus is transporting all of the volumes from Shell's Appomattox platform. Proteus completed construction of the new connecting platform adjacent to SP 89E platform that is accommodating volumes from the Mattox pipeline. In addition, the new Proteus platform can provide space for future pumping equipment and the ability to increase the capacity of the Proteus system to over 700 kbpd.

Ownership and Operatorship. We own a 65% managing member interest in Mardi Gras, which owns a 65% interest in Proteus. Certain unaffiliated third-party investors own a 10% and 25% interest, respectively, in Proteus. An affiliate of Shell operates Proteus. Under the Proteus limited liability company agreement, Proteus is managed by a management committee that has authority to manage the business and affairs of the Proteus pipeline system. All decisions of the management committee require the vote of two or more members that are not affiliates holding at least 60% of the ownership interests in Proteus, except

for certain significant actions, such as approving significant capital expenditures, that require the vote of members representing at least 76% of the ownership interests, and certain fundamental actions, such as authorizing the merger, consolidation or dissolution of the company, that require the vote of members representing 100% of the ownership interests.

The Proteus limited liability company agreement provides for cash distributions to the members from time to time, and the management committees may from time to time issue capital call notices to the members. Under the Proteus limited liability company agreements, each member's interest is subject to transfer restrictions, including a right of first refusal in favor of the other members. Subject to certain exceptions, the Proteus limited liability company agreements provide that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the vote of a unanimous interest.

Customers. Proteus maintains a set of well-established customers, including BP. Proteus is connected to the Thunder Horse and Thunder Hawk production platforms and Appomattox production platform via the Mattox Pipeline. Thunder Hawk is also connected to the Big Bend and Dantzler producing fields via a subsea tie-back. The BP Thunder Horse platform is BP's largest in the Gulf of Mexico, with production capacity of 250 kbpd and 200 MMscf/d.

Contracts. Since Proteus is not FERC-regulated under the ICA, in order to ship on Proteus, an oil transportation agreement is negotiated to cover transportation service. Pursuant to any such oil transportation agreement, shippers are generally required to dedicate the production from the fields to Proteus for the life of the applicable lease as a way to ensure the production moves on Proteus.

Endymion.

General. Endymion is an approximately 90 mile, 30-inch crude oil pipeline system which originates downstream of the SP 89E platform with an approximate current capacity of 425 kbpd and provides transportation for multiple oil producers in the eastern Gulf of Mexico. Endymion receives 100% of volumes transported on Proteus and is connected to the LOOP storage complex. Endymion leases a cavern from LOOP LLC, which provides it with additional operational flexibility and protection for its operations from extreme weather conditions such as hurricanes. The SP 89E platform has been connected with the Mattox pipeline and it has a connection to the Proteus Pipeline. Proteus is connected to the Thunder Horse and Thunder Hawk production platforms. Mattox Pipeline is connected to the Appomattox production platform. Thunder Hawk is also connected via subsea tie-backs to Big Bend and Dantzler producing fields. BP is the operator and has a 75% interest in Thunder Horse, which commenced production in 2008.

Ownership and Operatorship. We own a 65% managing member interest in Mardi Gras, which owns a 65% interest in Endymion, and unaffiliated third-party investors own the remaining 35%. An affiliate of Shell operates Endymion. Under the Endymion limited liability company agreement, Endymion is managed by a management committee that has authority to manage the business and affairs of the Endymion pipeline system. All decisions of the management committee requires the vote of two or more members that are not affiliates holding at least 60% of the ownership interests in Endymion, except for certain significant actions, including approving significant capital expenditures, that require the vote of members representing at least 76% of the ownership interests, and certain fundamental actions, including authorizing the merger, consolidation or dissolution of the companies, each of which requires the vote of members representing 100% of the ownership interests.

The Endymion limited liability company agreement provides for cash distributions to the members from time to time, and the management committee may from time to time issue capital call notices to the members. Under the Endymion limited liability company agreement, each member's interest is subject to transfer restrictions, including a right of first refusal in favor of the other members. Subject to certain exceptions, the Endymion limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the vote of a unanimous interest.

Customers. Endymion maintains a set of well-established customers, including BP. Endymion is connected to Proteus, which receives volumes from the Thunder Horse, Thunder Hawk, Big Bend, Dantzler and Appomattox production platforms via the Proteus Pipeline.

Contracts. Since Endymion is not FERC-regulated under the ICA, in order to ship on Endymion, an oil transportation agreement is negotiated to cover transportation service. Pursuant to any such oil transportation agreement, shippers are generally required to dedicate the production from the fields to Endymion for the life of the applicable lease as a way to ensure the production moves on Endymion.

Ursa.

General. Ursa is a pipeline that transports crude oil production from a platform located in the Mississippi Canyon area to a connection with the Mars Pipeline at West Delta 143 platform for ultimate transportation to Chevron's Fourchon terminal and LOOP caverns in Clovelly, Louisiana. Ursa is an 18-inch pipeline stretching approximately 47 miles sized to support a production peak of at least 150,000 barrels per day.

Ownership and Operatorship. We own a 22.7% member interest in Ursa and unaffiliated third-party investors own the remaining 77.3%. An affiliate of Shell operates Ursa. Under the Ursa limited liability company agreement, Ursa is managed by a management committee that has full power and authority to manage the entire business and affairs of the Ursa pipeline systems. Decisions of the management committee require the vote of a majority interest meaning more than 50% among two or more members that are not affiliates or super majority interest meaning three or more members having among them 80% or more of the membership interests of all members or approval of all the Members.

The Ursa limited liability company agreement provides for cash distributions to the members on a quarterly basis as determined by the members who were record holders as of the record date in accordance with their respective membership interest. Under the Ursa limited liability company agreement, each member's interest is subject to transfer restrictions, including that the transferee must have a net worth of $10,000,000 or greater than the net worth of the transferor on the date of the agreement or immediately prior to the date of transfer. Subject to certain exceptions, the Ursa limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the terms of the limited liability company agreement.

Customers. Ursa maintains a set of well-established customers, including BP.

Contracts. Ursa operates under a joint tariff with Mars Oil Pipeline Company, LLC.

KM Phoenix.

General. KM Phoenix is a terminal system that consists of 13 refined products terminals located across the United States with approximately 8.9 million barrels of storage and associated infrastructure. The terminals are located within key product trading hubs and highly strategic markets that support BP's refining, trading and marketing businesses. KM Phoenix has terminals located near key product trading hubs in New York, Chicago and the San Francisco Bay area. KM Phoenix serves gasoline and diesel needs for New York, Chicago, San Francisco, St Louis, Atlanta, Baltimore, Indianapolis, Cincinnati and Dayton, Ohio. KM Phoenix provides storage for production from BP's three refineries. Seven of KM Phoenix's terminals are supplied directly by BP's refineries and four terminals are directly supplied from BP's Whiting Refinery.

Ownership and Operatorship. We own a 25% member interest in KM Phoenix and the remaining 75% is owned by an affiliate of Kinder Morgan. An affiliate of Kinder Morgan operates KM Phoenix. Under the KM Phoenix limited liability company agreement, KM Phoenix is managed by its managers that comprise a board that has full power and authority to manage the entire business and affairs of KM Phoenix. A quorum of the board requires attendance of managers comprising a super-majority or 85% or more of the membership interests which are not in default at such time. The consent of the board to take any action requires 51% or more of all membership interests which are not in default at the time such action is being taken. Some board actions require a super-majority consent of the board or 85% or more of all membership interests which are not in default at the time such actions are being taken.

The KM Phoenix limited liability company agreement provides for cash distributions to the members within 30 days following the end of each calendar quarter. All available cash for the previous calendar quarter is distributed in proportion to their respective membership interest. Under the KM Phoenix limited liability company agreement, each member's interest is subject to transfer restrictions as outlined in the agreement. Subject to certain exceptions, the KM Phoenix limited liability company agreement provides that the company's existence shall continue indefinitely unless dissolved earlier pursuant to the terms of the limited liability company agreement.

Customers. KM Phoenix maintains a number of customers with BP being the primary customer.

Contracts. KM Phoenix has a variety of different contracts for customers' storage and throughput needs.

Our Commercial Agreements with BP

Minimum Volume Commitment Agreements

Our onshore assets provide vital movements to and from, and are integral to the operation of, BP's Whiting Refinery. We have commercial agreements with BP Products for our onshore pipelines that include minimum volume commitments and support substantially all of our aggregate revenue on BP2, River Rouge and Diamondback. Under these fee-based agreements, we provide transportation services to BP Products, and BP Products has committed to pay us for minimum volumes of crude oil, refined products and diluent, regardless of whether such volumes are physically shipped by BP Products through our pipelines during the term of the agreements.

Pipeline	Period	Annual Minimum Throughput Commitment (kbpd)	Transportation Fee Rate
BP2	Q4 2017 - 2018	303	Posted Tariff
BP2	2019	310	Posted Tariff
BP2	2020	320	Posted Tariff
River Rouge	Q4 2017 - 2020	60	Posted Tariff
Diamondback	Q3 2017 - Q2 2021	23	Posted Tariff
Diamondback	Q4 2017 - 2020	20	Posted Tariff

Under each of our throughput and deficiency, or "minimum volume commitment," agreements, BP Products is obligated to throughput certain minimum volumes of crude oil, refined products and diluent on our onshore pipelines and pay the applicable tariff rates with respect to such volumes. The following sets forth additional information regarding each of our minimum volume commitment agreements:

BP2 Throughput and Deficiency Agreement. Under this agreement, if BP Products fails to transport its minimum throughput volume on our BP2 pipeline from Griffith, Indiana to the Whiting Refinery during any month through December 31, 2020, then BP Products will pay us a deficiency payment equal to the volume of the deficiency multiplied by the contractual rate, which is calculated based on the applicable tariff rate then in effect. The amount of any deficiency payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on our BP2 pipeline in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

River Rouge Throughput and Deficiency Agreement. Under this agreement, if BP Products fails to transport its minimum throughput volume on River Rouge from Whiting, Indiana to various terminals along the pipeline during any month through December 31, 2020, then BP Products will pay us a deficiency payment equal to the volume of the deficiency multiplied by the contractual deficiency rate which is calculated based on the applicable tariff rates then in effect (the "Deficiency Payment"). The amount of any Deficiency Payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on River Rouge in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

Diamondback Throughput and Deficiency Agreements. We are a party to two throughput and deficiency agreements and one dedication agreement with BP Products for Diamondback. The dedication agreement and one throughput and deficiency agreement will renew in June 2020 pursuant to their terms for one additional year. The parties have the option to allow the two agreements to renew annually for one additional year by not sending written notice of termination six months prior to the expiration date. The throughput and deficiency agreement that does not have renewal terms expires on December 31, 2020. The Partnership is reviewing its options with respect to that agreement. Under the first such agreement, if BP Products fails to transport its minimum throughput volume on our Diamondback pipeline from Gary, Indiana to Manhattan, Illinois during any of the twelve month periods beginning on July 1, 2017 and each successive anniversary thereafter, then BP Products will pay us, during such period, a Deficiency Payment equal to the volume of the deficiency multiplied by the contractual rate, which is calculated based on the applicable tariff rate then in effect. Under the second such agreement, effective October 30, 2017, if BP Products fails to transport its minimum throughput volume on our Diamondback pipeline from Gary, Indiana to Manhattan, Illinois during any month through December 31, 2020, then BP Products will pay us a deficiency payment equal to the volume of the deficiency multiplied by the contractual rate, which is calculated based on the applicable tariff rate then in effect. The amount of any deficiency payment paid by BP Products under this agreement may be applied as a credit for any volumes transported on our Diamondback pipeline in excess of BP Products' minimum volume commitment during the calendar year in which such credits arose, after which time any unused credits will expire.

Termination of Throughput and Deficiency Agreements. BP Products has the right to terminate these agreements if we fail to perform any of our material obligations and fail to correct such non-performance within specified periods, or, for the agreements that run through December 31, 2020, in the event of a change of control of our general partner.

BP Products is not permitted to suspend or reduce its obligations under these agreements in connection with the shutdown of the Whiting Refinery for any reason other than certain force majeure events, including for scheduled maintenance or other regular servicing or maintenance.

Under these agreements, if a force majeure event occurs and renders us or BP Products unable to meet our respective obligations under the agreement and continues for 365 consecutive days or more, then the party not claiming non-performance due to such force majeure event shall have the right to terminate the agreement on no less than 30 days' prior written notice to the other party.

Right of First Offer

We have entered into an omnibus agreement with BP Pipelines under which BP Pipelines granted us a ROFO, for a period ending on the earlier of (i) seven years after the IPO or (ii) the date on which BP Pipelines or its affiliates cease to control our general partner. Pursuant to the ROFO, BP Pipelines has agreed and will cause its affiliates to agree that if BP Pipelines or any of its affiliates decide to attempt to sell (other than to another affiliate of BP Pipelines) BP Pipelines' retained ownership interest in Mardi Gras and all of BP Pipelines' interests in midstream pipeline systems and assets related thereto in the contiguous United States and offshore Gulf of Mexico that were owned by BP Pipelines at the closing of the IPO (the "Subject Assets"), BP Pipelines or its affiliate will notify us of its desire to sell such Subject Assets and, prior to selling such Subject Assets to a third party, will allow us 45 days from such notice to make a binding written offer regarding such Subject Assets. In addition to BP Pipelines' retained ownership interest in Mardi Gras, the assets subject to our ROFO include three crude oil and natural gas liquid pipeline systems with an aggregate gross length of approximately 1,550 miles and an aggregate gross capacity of approximately 1,800 kbpd and nine refined products pipeline systems with an aggregate gross length of approximately 1,940 miles and an aggregate gross capacity of approximately 620 kbpd, as of December 31, 2019.

The consideration to be paid by us for the Subject Assets, as well as the consummation and timing of any acquisition by us of those assets, would depend upon, among other things, the timing of BP Pipelines' decision to sell those assets and our ability to successfully negotiate a price and other mutually agreeable purchase terms for those assets. Please see *Part I, Item 1A. Risk Factors—Risks Related to Our Business*—If we are unable to make acquisitions on economically acceptable terms from BP or third parties, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Payment of Administrative Fee and Reimbursement of Expenses

Under the omnibus agreement, we initially agreed to pay BP Pipelines an administrative fee of $13.3 million annually (payable in equal monthly installments), to reimburse BP Pipelines and its affiliates for the provision of certain general and administrative services for our benefit, including services related to the following areas: executive management services; financial management and administrative services (such as treasury and accounting); information technology services; legal services; health, safety and environmental services; land and real property management services; human resources services; procurement services; corporate engineering services; business development services; investor relations, communications and external affairs; insurance administration and tax related services.

Under this agreement, we initially agreed to also reimburse BP Pipelines and its affiliates for all other direct or allocated costs and expenses incurred by BP Pipelines in providing these services to us, including personnel costs related to the direct operation, management, maintenance and repair of the assets. This reimbursement is in addition to our reimbursement of our general partner and its affiliates for certain costs and expenses incurred on our behalf for managing and controlling our business and operations as required by our partnership agreement.

The fee was adjusted to $13.6 million per year, payable in equal monthly installments, beginning on January 1, 2019, and adjusted to $15.2 million per year, payable in equal monthly installments, beginning on January 1, 2020. Our general partner, in good faith, may adjust the administrative fee to reflect, among others, any change in the level or complexity of our operations, a change in the scope or cost of services provided to us, inflation or a change in law or other regulatory requirements, the contribution, acquisition or disposition of our assets or any material change in our operation activities.

Customers

BP is our primary customer. Total revenue from BP represented 97.6%, 97.6%, and 98.0% of our revenues in the years ended December 31, 2019, 2018 and 2017, respectively. BP's volumes represented approximately 95.1%, 94.9% and 95.3% of the aggregate total volumes transported on the Wholly Owned Assets for the years ended December 31, 2019, 2018 and 2017, respectively.

In addition, we transport crude oil, natural gas and diluent for a mix of third-party customers, including crude oil producers, refiners, marketers and traders, and our assets are connected to other crude oil, natural gas and diluent pipeline systems. In addition to serving directly connected Midwestern U.S. and Gulf Coast markets, our pipelines have access to customers in various regions of the United States and Canada through interconnections with other major pipelines. Our customers use our transportation services for a variety of reasons. Producers of crude oil require the ability to deliver their product to market and frequently enter into firm transportation contracts to ensure that they will have sufficient capacity available to deliver their product to delivery points with greatest market liquidity. Marketers and traders generate income from buying and selling crude oil, natural gas, refined products and diluent to capitalize on price differentials over time or between markets. Our customer mix can vary over time and largely depends on the crude oil, natural gas, refined products and diluent supply and demand dynamics in our markets.

Competition

Our pipelines face competition from a variety of alternative transportation methods including rail, water borne movements including barging and shipping, trucking and other pipelines that service the same markets as our pipelines. Competition for BP2 and River Rouge common carrier pipelines is based primarily on connectivity to sources of supply and demand. Both of these lines are integral to the Whiting Refinery and there are a limited number of competitors providing similar services. For example, BP2 provides the primary supply of crude oil (including heavy crude) to the Whiting Refinery, and River Rouge is the sole source of refined products for three of the five third-party terminals along its route to the Detroit refined products market. We believe that Diamondback offers a unique level of service to our customers for diluent that moves to Canada on a third-party pipeline connected to the delivery point of Diamondback. However, Diamondback competes with one or more pipelines for Gulf Coast sourced diluent, including pipelines that have direct connections in Manhattan, Illinois and which may develop additional access to Western Canadian producers in the future. Our terminals compete for throughput and storage opportunities in the geographic areas in which they operate.

Competition for refined products in the Midwest is affected by supply and demand. Supply is driven by the volume of products produced by refineries in that area, the availability of products to get transported to the area and the cost of transportation to that area from other geographies. As a result of our affiliate relationships and the scope and scale of our refined products pipeline system, we believe that our refined product pipeline will not face significant new competition in the near-term.

Even though our offshore lines are supported by fee-based life-of-lease transportation agreements, our offshore pipeline compete for new production on the basis of geographic proximity to the production, cost of connection, available capacity, transportation rates and access to onshore markets. The principal competition for our offshore pipeline includes other crude oil and natural gas pipeline systems as well as producers who may elect to build or utilize their own transportation assets, although the barrier to new entrants is high due to the cost and environmental permitting required. In addition, the ability of our offshore pipelines to access future reserves will be subject to our ability, or the producers' ability, to fund the significant capital expenditures required to connect to the new production. In general, except for Mars, our offshore pipelines are not currently subject to regulatory rate-making authority, and the rates our offshore pipeline charges for services are dependent on market and economic conditions.

FERC and Common Carrier Regulations

Our common carrier pipeline systems are subject to regulation by various federal, state and local agencies.

FERC regulates interstate transportation on our common carrier refined products, diluent, and crude oil pipeline systems under the ICA as modified by the Elkins Act, the EPAct and the rules and regulations promulgated under those laws. FERC regulations require that rates and terms and conditions of service for interstate service pipelines that transport crude oil, refined products and diluent (collectively referred to as "petroleum pipelines") and certain other liquids, be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC's regulations also require interstate common carrier petroleum pipelines to file with FERC and publicly post tariffs stating their interstate transportation rates and terms and conditions of service.

Under the ICA, FERC or interested persons may challenge either existing or proposed new or changed rates, services, or terms and conditions of service. FERC is authorized to investigate such charges and may suspend the effectiveness of a new rate for up to seven months. Under certain circumstances, FERC could limit a common carrier pipeline's ability to charge rates until completion of an investigation during which FERC could find that the new or changed rate is unlawful. In contrast, FERC has clarified that initial rates and terms of service agreed upon with committed shippers in a transportation services agreement are not subject to protest or a cost-of-service analysis where the pipeline held an open season offering all potential shippers service on the same terms.

A successful rate challenge could result in a common carrier pipeline paying refunds of revenue collected in excess of the just and reasonable rate, together with interest for the period, if any, that the rate was in effect. FERC may also order a pipeline to reduce its rates prospectively and may require a common carrier pipeline to pay shippers reparations retroactively for rate overages for a period of up to two years prior to the date the complaint was filed. FERC also has the authority to require changes to a pipeline's terms and conditions of service if it determines that they are unjust or unreasonable or unduly discriminatory or preferential. We may at any time also be required to respond to governmental requests for information, including compliance audits conducted by FERC.

The EPAct required FERC to establish a simplified and generally applicable methodology to adjust tariff rates for inflation for interstate petroleum pipelines. As a result, FERC adopted an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the PPI. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG plus 1.23%. We cannot predict whether or to what extent the index factor may change in the future. As discussed below, FERC's March 15, 2018 Revised Policy on Treatment of Income Taxes ("Revised Policy Statement") proposes to reflect the effects of its new policy in the 2020 five-year review. A pipeline is not required to raise its rates up to the index ceiling, but it is permitted to do so. Rate increases made under the index are presumed to be just and reasonable and require a protesting party to demonstrate that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. Despite these procedural limits on challenging the indexing of rates, the overall rates are not entitled to any specific protection against rate challenges. Under the indexing rate methodology, in any year in which the index is negative, pipelines must file to lower their rates if those rates would otherwise be above the rate ceiling.

On October 20, 2016, FERC issued an Advance Notice of Proposed Rulemaking regarding Revisions to Indexing Policies and Page 700 of FERC Form No. 6 (the "ANOPR"). If final rules were implemented as proposed in the ANOPR, then FERC would implement new tests for whether our pipelines providing service subject to FERC tariffs could increase rates in accordance with the FERC index in a given year and the new tests could restrict our ability to increase our rates as a result. Effective February 21, 2020, FERC withdrew the ANOPR.

While common carrier pipelines often use the indexing methodology to change their rates, common carrier pipelines may elect to support proposed rates by using other methodologies such as cost-of-service ratemaking, market-based rates, and settlement rates. A common carrier pipeline can propose a cost-of-service approach when seeking to increase its rates above the rate ceiling (or when seeking to avoid lowering rates to the reduced rate ceiling), but must establish that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. A common carrier can charge market-based rates if it establishes that it lacks significant market power in the affected markets. A common carrier can change existing rates under settlement if agreed upon by all current shippers. Initial rates for a new service on a common carrier pipeline can be established through a negotiated rate with an unaffiliated shipper, but if challenged must be supported by a cost of service.

The rates shown in our tariffs have been established using a cost-of-service methodology, by settlement or contract negotiation, by indexing, or by a combination of these methods. FERC utilizes an indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the PPI. The indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by Producer's Price Index for Finished Goods ("PPI-FG") plus 1.23%. Many existing pipelines, including BP2, River Rogue, Diamondback, and Mars, utilize the FERC oil index to change transportation rates annually every July 1.

On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. To the extent a regulated entity is permitted to include an income tax allowance in its cost-of-service, FERC directed entities to calculate the income tax allowance at the reduced 21% maximum corporate tax rate established by the Tax Cuts and Jobs Act. FERC also issued the Revised Policy Statement stating that it will no longer permit MLPs to recover an income tax allowance in their cost-of-service rates. FERC requires oil and refined products pipelines subject to FERC jurisdiction to reflect the impacts to their cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act on the Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act in the determination of indexed rates prospectively, effective July 1, 2021. FERC’s establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC’s determination of the appropriate pipeline index. Accordingly, depending on FERC’s application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates. While management continues to evaluate the FERC issuances related to the treatment of federal income tax allowances, we do not expect this to have a material impact on our tariffs or our cash available for distribution.

Intrastate services provided by certain of our pipeline systems are subject to regulation by state regulatory authorities, such as the Louisiana Public Service Commission, which currently regulates Mars. State agencies typically require intrastate petroleum pipelines to file their rates with the agencies and permit shippers to challenge existing rates and proposed rate increases. State agencies may also investigate rates, services, and terms and conditions of service on their own initiative. State regulatory commissions could limit our ability to increase our rates or to set rates based on our costs or order us to reduce our rates and require the payment of refunds to shippers.

If our rate levels were investigated by FERC or a state commission, the inquiry could result in an investigation of our costs, including:

- the overall cost of service, including operating costs and overhead;
- the allocation of overhead and other administrative and general expenses to the regulated entity;
- the appropriate capital structure to be utilized in calculating rates;
- the appropriate rate of return on equity and interest rates on debt;
- the rate base, including the proper starting rate base;
- the throughput underlying the rate; and
- the proper allowance for federal and state income taxes.

FERC or a state commission could order us to change our rates, services, or terms and conditions of service or require us to pay shippers reparations, together with interest and subject to the applicable statute of limitations, if it were determined that an established rate, service, or terms and conditions of service were unjust or unreasonable or unduly discriminatory or preferential.

The FERC implements the OCSLA pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide non-discriminatory transportation service. The Caesar, Cleopatra, Proteus, and portions of Endymion, Mars and Ursa pipelines are located in the Outer Continental Shelf and are subject to the non-discrimination requirements in the OCSLA.

Safety

Our assets are subject to stringent safety laws and regulations. Our transportation of crude oil, natural gas, refined products and diluent involves a risk that hazardous liquids or flammable gases may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, and significant business interruption. PHMSA of DOT has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our assets. BSEE of DOI has adopted similar regulations for offshore pipelines under its jurisdiction. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and necessary maintenance or repairs. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

Pipeline safety laws and regulations are subject to change over time. Changes in existing laws and regulations could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition. For example, PHMSA issued the Safety of Hazardous Liquids Pipelines final rule on October 1, 2019. This final rule addressed topics such as: inspections of onshore and offshore pipelines following extreme weather events or natural disasters, periodic assessment of pipelines not currently subject to integrity management, expanded use of leak detection systems, increased use of in-line inspection tools, and other requirements. For example, the new PHMSA rule requires operators of onshore pipeline segments that can accommodate in-line inspection ("ILI") tools that are not currently subject to integrity management requirements to complete assessments using ILI tools at least once every ten years. The new rule also requires that all hazardous liquids pipelines located in high consequence areas ("HCAs") or areas that could affect HCAs be capable of accommodating ILI tools within 20 years unless certain limited exceptions apply. PHMSA also issued the Safety of Gas Transmission Pipelines final rule on October 1, 2019. This final rule addressed topics such as: maximum allowable operating pressure, expansion of integrity management requirements to previously non-regulated pipelines, and other requirements. We are currently evaluating impacts related to both rulemakings, although no significant new requirements have been identified. Additional rulemakings related to pipeline safety are expected to be issued in 2020.

For the pipelines we operate, we monitor the structural integrity of our pipelines through a program of periodic internal assessments using high resolution internal inspection tools, as well as hydrostatic testing that conforms to federal standards. We accompany these assessments with a review of the data and repair anomalies, as required, to ensure the integrity of each pipeline. We compare these inspection and testing results with other inspection data to ensure that the highest risk pipelines receive the highest priority for consideration of additional integrity assessments or repairs. We use external coatings and impressed current cathodic protection systems to protect against external corrosion. We conduct all cathodic protection work in accordance with all state and federal regulations, and we regularly monitor, test, and record the effectiveness of these corrosion inhibiting systems. We operate BP2, Diamondback and River Rouge.

Mars, Ursa and the Mardi Gras Joint Ventures are operated in a similar manner by an affiliate of Shell. KM Phoenix's terminalling assets are operated in a similar manner by an affiliate of Kinder Morgan.

Product Quality Standards

Refined products that we transport are generally sold by our customers for consumption by the public. Various federal, state and local agencies have the authority to prescribe product quality specifications for refined products. Changes in product quality specifications or blending requirements could reduce our throughput volumes, require us to incur additional handling costs or require capital expenditures. For example, different product specifications for different markets affect the fungibility of the refined products in our system and could require the construction of storage. In addition, changes or variations in product specifications of the refined products we receive on our refined product pipeline systems could add operational and scheduling complexity due to movements of additional product segregations on the pipeline. Our inability to recover increased expenditures for infrastructure or operational costs could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions.

Security

We are subject to the Transportation Security Administration's Pipeline Security Guidelines, and some of the pipelines have been identified as Critical Infrastructure Assets. Further, the SP 89E platform associated with Proteus is subject to Maritime Transportation Safety Act requirements through the U.S. Coast Guard. We have an internal program of inspection designed to monitor and enforce compliance with all of these requirements. We believe that we are in material compliance with all applicable laws and regulations regarding the security of our facilities.

While we are not currently subject to governmental standards for the protection of computer-based systems and technology from cyber threats and attacks, proposals to establish such standards are being considered by the U.S. Congress and by U.S. Executive Branch departments and agencies, including the Department of Homeland Security, and we may become subject to such standards in the future. We are currently implementing our own cyber-security programs and protocols; however, we cannot guarantee their effectiveness. A significant cyber-attack could have a material effect on operations and those of our customers.

Environmental Matters

General. Our operations are subject to federal, state and local laws, regulations and ordinances relating to the protection of the environment and natural resources. Among other things, these laws and regulations govern the emission or discharge of pollutants into or onto the land, air and water, the handling and disposal of solid and hazardous wastes and the remediation of contamination. Compliance with existing and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, operate and upgrade equipment and facilities. While these laws and regulations affect our maintenance capital expenditures and net income, we believe they do not affect our competitive position, as the operations of our competitors are similarly affected. These laws and regulations are subject to changes, or to changes in the interpretation of such laws and regulations, by regulatory authorities, and continued and future compliance with such laws and regulations may require us to incur significant expenditures. Violation of environmental laws, regulations, and permits can result in the imposition of significant administrative, civil and criminal penalties, injunctions limiting our operations, investigatory or remedial liabilities or construction bans or delays in the construction of additional facilities or equipment. Additionally, a release of hydrocarbons or hazardous substances into the environment could, to the extent the event is not insured, subject us to substantial expenses, including costs to comply with applicable laws and regulations and to resolve claims by third parties for personal injury or property damage, or by the U.S. federal government or state governments for natural resources damages. These impacts could directly and indirectly affect our business and have an adverse impact on our financial position, results of operations, and liquidity. We cannot currently determine the amounts of such future impacts.

Air Emissions. Our operations are subject to the federal Clean Air Act and its regulations and comparable state and local statutes and regulations in connection with air emissions from our operations. Under these laws, permits may be required before construction can commence on a new source of potentially significant air emissions, and operating permits may be required for sources that are already constructed. These permits may require controls on our air emission sources, and we may become subject to more stringent regulations requiring the installation of additional emission control technologies.

We cannot predict the potential impact of climate change legislation and regulations to address air emissions in the United States or of any climate-related litigation on our future consolidated financial condition, results of operations or cash flows. However, changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could impact our assets, costs, revenue generation and growth opportunities.

Waste Management and Related Liabilities. To a large extent, the environmental laws and regulations affecting our operations relate to the release of hydrocarbons, hazardous substances or solid wastes into soils, groundwater, and surface water, and include measures to control pollution of the environment. These laws generally regulate the generation, storage, treatment, transportation, and disposal of solid and hazardous waste. They also require corrective action, including investigation and remediation, at a facility where such waste may have been released or disposed.

CERCLA. CERCLA and comparable state laws impose liability, without regard to fault or to the legality of the original conduct, on certain classes of persons that contributed to the release of a “hazardous substance” into the environment. These persons include the former and present owner or operator of the site where the release occurred and the transporters and generators of the hazardous substances found at the site. While CERCLA contains a "petroleum exclusion" we could still be subject to liability under this statue as a result of release of hazardous substances not subject to this exemption (such as tank bottom sludges or chemicals used to clean equipment), or as the result of such substances co-mingling with petroleum or petroleum products.

Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, we generate waste that falls within CERCLA’s definition of a “hazardous substance” and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites where any such hazardous substances may have been disposed and any related natural resource damages. We also may have similar liabilities under state laws comparable to CERCLA.

RCRA. We also generate solid wastes, and despite RCRA's exclusion for oil and natural gas exploration and production wastes, some hazardous wastes (such as pipeline pigging waters and equipment lubricants), that are subject to the requirements of the federal RCRA and comparable state statutes. From time to time, the EPA and states consider the adoption of stricter disposal standards for non-hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements

than are non-hazardous wastes. Significant changes in the regulations could increase our maintenance capital expenditures and operating expenses.

Hydrocarbon Wastes. We currently own and lease properties where hydrocarbons are being or for many years have been handled. Over time, hydrocarbons or waste may have been disposed of or released on or under our properties or on or under other locations where hydrocarbons and wastes were taken for disposal. In addition, many of these properties and locations have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and certain hydrocarbons and wastes disposed thereon may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater), or to take actions to prevent further contamination.

Indemnity Under the Omnibus Agreement. Under the omnibus agreement, BP Pipelines will indemnify us for all known and certain unknown environmental liabilities that are associated with the ownership or operation of certain of our assets and due to occurrences on or before October 30, 2017, subject to certain limitations. Indemnification for any unknown environmental liabilities will be limited to liabilities due to occurrences on or before October 30, 2017, which are identified prior to October 30, 2020, and will be subject to an aggregate deductible of $0.5 million before we are entitled to indemnification for losses incurred. Once we meet the deductible, BP Pipelines' indemnity obligation for environmental claims that are unknown as of October 30, 2017 and litigation claims pending as of October 30, 2017 is capped at $15 million. Indemnification for known environmental liabilities identified in the omnibus agreement is not subject to a deductible; however, BP Pipelines' indemnity obligation for these identified environmental liabilities is capped at $25 million. We will not be indemnified for any spills or releases of hydrocarbons or hazardous materials at our facilities that occur after October 30, 2017, or for any other environmental liabilities resulting from our own operations. In addition, we initially agreed to indemnify BP Pipelines for losses arising out of, or associated with, the ownership, management or operation of the IPO Contributed Assets, whether related to the period before or after October 30, 2017 to the extent BP Pipelines is not required to indemnify us for such losses. Losses for which we will indemnify BP Pipelines pursuant to the omnibus agreement are not subject to a deductible before BP Pipelines is entitled to indemnification. There is no limit on the amount for which we will indemnify BP Pipelines under the omnibus agreement. As a result, we may incur such expenses in the future, which may be substantial.

Water. Our operations can result in the discharge of pollutants, including crude oil, natural gas, refined products and diluent. Regulations under the Clean Water Act, OPA-90 and state laws impose regulatory burdens on our operations. The discharge of pollutants into jurisdictional waters is prohibited, except in accordance with the terms of a permit issued by the EPA, U.S. Army Corps of Engineers (the "Corps"), or a delegated state agency. We obtain discharge permits as required under the National Pollutant Discharge Elimination System program of the Clean Water Act or state laws as needed for maintenance or hydrostatic testing activities. In addition, the Clean Water Act and analogous state laws require coverage under general permits for discharges of storm water runoff from certain types of facilities.

The transportation of crude oil, natural gas, refined products and diluent over and adjacent to water involves risk and subjects us to the liability provisions of and certain regulations issued pursuant to OPA-90 and related state requirements. Among other requirements, OPA-90 requires the owner or operator of a tank vessel or a facility to maintain an emergency plan to respond to releases of oil or hazardous substances. PHMSA and BSEE have promulgated regulations requiring such plans that apply to our onshore and offshore pipelines. With respect to statutory liability, in case of any such release, OPA-90 requires the responsible company to pay resulting removal costs and damages. OPA-90 also provides for civil penalties and imposes criminal sanctions for violations of its provisions. We operate facilities at which releases of oil and hazardous substances could occur. OPA-90 applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA-90 has the potential to adversely affect our operations.

Construction or maintenance of our pipelines may impact "Waters of the United States" under the Clean Water Act. A 2015 rule defining the scope of federal jurisdiction over such waters was repealed in December 2019, and in January 2020 the EPA and the Corps finalized the Navigable Waters Protection Rule, which narrows the definition of "Waters of the United States" relative to the prior 2015 rulemaking. However, legal challenges to the new rule are expected, and multiple challenges to the EPA and the Corps' prior rulemakings remain pending. As a result, future implementation of the new rule is uncertain. To the extent any rule on the scope of federal jurisdiction over such waters ultimately expands the range of properties subject to the Clean Water Act's jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which in turn could reduce demand for our services. Regulatory requirements governing wetlands or river crossings (including associated mitigation projects) may result in the delay of our pipeline projects while we obtain necessary permits and may increase the cost of new projects and maintenance activities.

Employee Safety. We are subject to the requirements of the OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. While some of our facilities are in areas that may be designated as habitat for endangered species, to date, we have not experienced any material adverse impacts as a result of compliance with the Endangered Species Act. If current or future-listed endangered or threatened species or critical habitat are located in areas of the underlying properties where we wish to conduct development activities associated with construction, such work could be prohibited or delayed or expensive mitigation may be required. The U.S. Fish and Wildlife Service periodically makes determinations on listing of numerous species as endangered or threatened under the Endangered Species Act. The discovery of previously unidentified endangered species or threatened species or the designation and listing of new endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected area.

National Environmental Policy Act. Major federal actions, such as the issuance of permits associated with construction, can require the completion of certain reviews under the NEPA. NEPA requires federal agencies, including the Corps, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increasing the costs of permitting and developing some facilities and could result in certain instances in the abandonment of proposed projects. In January 2020, the Council on Environmental Quality issued a notice of proposed rulemaking to update the NEPA regulations. The impact of changes to the NEPA regulations, if adopted, on our projects is uncertain.

Seasonality

Demand for crude oil, refined products and diluent generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain crude oil users utilize storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase demand during the summer and winter months and decrease demand during the spring and fall months. In respect of our completed midstream systems, we do not expect seasonal conditions to have a material impact on our throughput volumes, as many effects of seasonality on our revenue will be substantially mitigated through the use of our fee-based long-term agreements with BP Products that include minimum volume commitments. Severe or prolonged winters may, however, impact our ability to complete construction projects, which may impact our revenues and results of operations.

Title to Real Property Interests and Permits

While there are a limited number of fee-owned properties associated with certain of our pipeline assets, substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property and in some instances these rights-of-way are revocable at the election of the grantor. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that may not have been subordinated to the rights-of-way ("ROW") grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, watercourses, county roads, municipal streets, and state highways and, in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor’s election. In some states and under some circumstances, we have the right to seek the use of eminent domain power to acquire rights-of-way and lands necessary for our common carrier pipelines.

Insurance

Our assets are either self-insured or insured with third parties for certain property damage, business interruption and third-party liabilities, and such coverage includes sudden and accidental pollution liabilities, in amounts which management believes are reasonable and appropriate, and excludes named windstorm coverage.

Employees

Our operations are conducted through, and our assets are owned by, various subsidiaries. However, neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the personnel necessary to conduct our operations, whether through directly hiring personnel or by obtaining services of personnel employed by BP, BP Pipelines or third parties, but we sometimes refer to these individuals, for drafting convenience only, in this Annual Report as our employees because they provide services directly to us. These operations personnel primarily provide services with respect to the assets we operate: BP2, River Rouge and Diamondback. Mars, Ursa and the Mardi Gras Joint Ventures are operated by an affiliate of Shell. KM Phoenix is operated by an affiliate of Kinder Morgan. Under the omnibus agreement we are required to reimburse BP for all costs attributable to operating personnel services. A portion of the operations personnel who provide services for our onshore assets are represented by labor unions. We consider our labor relations to be good and have not experienced any material work stoppages or other material labor disputes within the last five years.

Pipeline Control Operations

BP2, River Rouge, and Diamondback, which are operated by BP Pipelines' employees, are controlled from a central control center located in Tulsa, Oklahoma. The control center operates with a Supervisory Control and Data Acquisition system equipped with computer systems designed to continuously monitor operational data. Monitored data includes pressures, temperatures, gravities, flow rates and alarm conditions. The control center operates remote pumps, motors, and valves associated with the receipt and delivery of crude oil and refined products, and provides for the remote-controlled shutdown of pump stations and valves on the pipeline system. A fully functional back-up operations center is also maintained and routinely operated throughout the year with the aim of ensuring safe, reliable, and compliant operations. Mars, Ursa and the Mardi Gras Joint Ventures are operated in a similar manner by an affiliate of Shell. The KM Phoenix storage and terminalling systems are operated by an affiliate of Kinder Morgan.

Website

Our Internet website address is http://www.bpmidstreampartners.com. Information contained on our Internet website is not part of this Annual Report on Form 10-K.

Our Annual Reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to these reports, filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, are available on our website, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC's website at http://www.sec.gov. We also post on our website our beneficial ownership reports filed by officers and directors of our general partner, as well as principal security holders, under Section 16(a) of the Exchange Act, corporate governance guidelines, audit committee charter, code of business conduct and ethics, financial code of ethics and information on how to communicate directly with our general partner's Board of Directors.

Item 1A. RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks which we are subject to are similar to those that would be faced by a corporation engaged in a similar business. If any of the following risks actually occur, they may materially harm our business and our financial condition and results of operations. In this event we might not be able to pay distributions on our common units, and the trading price of our common units could decline.

Risks Related to Our Business

We may not have sufficient cash available for distribution following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay minimum quarterly distributions to our unitholders.

The amount of cash available for distribution we must generate to support the payment for four quarters of minimum quarterly distributions on our common and subordinated units, outstanding as of December 31, 2019, is $110.0 million (or an average of approximately $27.5 million per quarter). However, we may not generate sufficient cash flows each quarter to enable us to maintain or grow our current distribution level, or to pay minimum quarterly distributions. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things, our throughput volumes, tariff rates and fees and prevailing economic conditions. In addition, the actual amount of cash flows we generate will also depend on other factors, some of which are beyond our control, including:

- the amount of our operating expenses and general and administrative expenses, including reimbursements to BP Pipelines and its affiliates with respect to those expenses;
- the amount and timing of capital expenditures and acquisitions we make;
- our debt service requirements and other liabilities, and restrictions contained in our debt agreements;
- fluctuations in our working capital needs;
- decisions made by BP with respect to the levels of production at its refineries that we serve and its obligations under our commercial agreements;
- our entitlements to payments associated with the minimum volume commitments under our commercial agreements with BP Products;
- the amount of cash distributed to us by the entities in which we own a non-controlling interest; and
- the amount of cash reserves established by our general partner.

BP Products is under no obligation to enter into new minimum volume commitment agreements following their respective terms and may terminate its obligations earlier under certain specified circumstances, which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

BP Products is under no obligation to enter into new minimum volume commitment agreements following their respective terms. Minimum volume commitment agreements for BP2, River Rouge and Diamondback expire in 2020, with an additional Diamondback minimum volume commitment agreement expiring in 2021. In addition, BP Products has the right to terminate these agreements prior to the end of their terms under certain specified circumstances, including (i) if we fail to perform any of our material obligations and fail to correct such non-performance within specified periods, and (ii) in the event of a change of control of our general partner. Minimum volume commitments under these agreements support a substantial portion of our revenues. As a result, any such termination of BP Products' obligations could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make distributions to our unitholders. Please read "Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements."

We own certain assets through joint ventures that we do not operate, and our control of such assets is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures.

We own a (i) 28.5% interest in Mars, a joint venture with certain affiliates of Shell that is operated by an affiliate of Shell, (ii) a 65% managing member interest in Mardi Gras, which owns a 56% ownership interest in Caesar, a 53% interest in Cleopatra, a 65% interest in Proteus and a 65% interest in Endymion, each of which is operated by an affiliate of Shell, (iii) 22.7% interest in Ursa, a joint venture with certain affiliates of Shell that is operated by an affiliate of Shell, and (iv) a 25% interest in KM Phoenix Holdings, a joint venture with certain affiliates of Kinder Morgan that is operated by an affiliate of Kinder Morgan. Through our managing member interest in Mardi Gras, we have the right to vote Mardi Gras' interest in the Mardi Gras Joint Ventures. As we do not operate the assets owned by these joint ventures, our control over their operations is limited

by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures. Our ability to make distributions to our unitholders depends on the performance of these joint ventures and their ability to distribute funds to us, and we may be unable to control the amount of cash we will receive from their operations, which could adversely affect our unitholders. More specifically:

- We do not control or operate Mars, Ursa, KM Phoenix or the Mardi Gras Joint Ventures and as a result, we only have limited ability to influence the business decisions of such joint venture entities.
- We do not directly control the amount of cash distributed by Mars, Ursa, KM Phoenix or any of the Mardi Gras Joint Ventures. We only influence the amount of cash distributed through our voting rights over the cash reserves made by such joint venture entities.
- We do not have the ability to unilaterally require Mars, Ursa, KM Phoenix or any of the Mardi Gras Joint Ventures to make capital expenditures.
- Our joint ventures may require us to make additional capital contributions to fund operating and maintenance expenses and maintenance capital expenditures, as well as to fund expansion capital expenditures, which would reduce the amount of cash otherwise available for distribution by us or require us to incur additional indebtedness.

In addition, because we have partial ownership in the joint ventures, we can only exercise limited review and perform limited queries into the accounting performed by the operators. We have no control over the actual day-to-day accounting performed by the operator. If our joint venture partners have control deficiencies in their accounting or financial reporting environments, it may result in reporting our percentage of the financial results for the joint venture that are inaccurate. This could result in a material misstatement in our reported consolidated financial results.

If we are unable to obtain needed capital or financing on satisfactory terms to fund any future expansions of our asset base, our ability to make quarterly cash distributions may be diminished or our financial leverage could increase. Other than our revolving credit facility, we do not have any commitment with any of our affiliates or third parties to provide any direct or indirect financial assistance to us.

We will be required to use cash from our operations, incur borrowings or access the capital markets in order to fund any future expansion capital expenditures. As of December 31, 2019, we have $132 million in available borrowings under our revolving credit facility. The entities in which we own an interest may also incur borrowings or access the capital markets to fund future capital expenditures. Our and their ability to obtain financing or access the capital markets may be limited by our or their financial condition at such time as well as the covenants in our or their debt agreements, general economic conditions and contingencies, or other uncertainties that are beyond our control. The terms of any such financing could also limit our ability to pay distributions to our common unitholders. Incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

If we are unable to make acquisitions on economically acceptable terms from BP or third parties, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders.

Our strategy to grow our business and increase distributions to unitholders is dependent in part on our ability to make acquisitions that result in an increase in cash available for distribution per unit. The consummation and timing of any future acquisitions will depend upon, among other things, whether we are able to:

- identify attractive acquisition candidates;
- negotiate acceptable purchase agreements;
- obtain financing for these acquisitions on economically acceptable terms; and
- outbid any competing bidders.

We have a ROFO pursuant to our omnibus agreement that requires BP Pipelines to allow us to make an offer with respect to the Subject Assets, to the extent BP Pipelines elects to sell those assets (other than to another affiliate of BP Pipelines). BP Pipelines is under no obligation to sell the Subject Assets or offer to sell us additional assets, we are under no obligation to buy any additional interests or assets from BP Pipelines and we do not know when or if BP Pipelines will decide to sell the Subject Assets or make any offers to sell assets to us. We may never purchase all or any portion of the assets subject to the ROFO for several reasons, including the following:

- BP Pipelines may choose not to sell the Subject Assets;
- we may not make acceptable offers for the Subject Assets;

- we and BP Pipelines may be unable to agree to terms acceptable to both parties;
- we may be unable to obtain financing to purchase the Subject Assets on acceptable terms or at all; or
- we may be prohibited by the terms of our debt agreements (including our credit facility) or other contracts from purchasing some or all of the Subject Assets, and BP Pipelines may be prohibited by the terms of its debt agreements or other contracts from selling some or all of the Subject Assets. If we or BP Pipelines must seek waivers of such provisions or refinance debt governed by such provisions in order to consummate a sale of the Subject Assets, we or BP Pipelines may be unable to do so in a timely manner or at all.

We can offer no assurance that we will be able to successfully consummate any future acquisitions, whether from BP or any third parties. If we are unable to make future acquisitions, our future growth and ability to increase distributions may be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash available for distribution per unit as a result of incorrect assumptions in our evaluation of such acquisitions or unforeseen consequences or other external events beyond our control. Acquisitions involve numerous risks, including difficulties in integrating acquired businesses, inefficiencies and unexpected costs and liabilities.

Our operations are subject to many risks and operational hazards. If a significant accident or event occurs that results in a business interruption or shutdown for which we are not adequately insured, our operations and financial results could be materially and adversely affected.

Our operations are subject to all of the risks and operational hazards inherent in transporting crude oil, natural gas, refined products and diluent, including:

- damages to pipelines, facilities, offshore pipeline equipment and surrounding properties caused by third parties, severe weather, natural disasters, including hurricanes, and acts of terrorism;
- mechanical or structural failures at our or BP Pipelines' facilities or at third-party facilities on which our customers' or our operations are dependent, including electrical shortages, power disruptions and power grid failures;
- damages to, loss of availability of and delays in gaining access to interconnecting third-party pipelines, terminals and other means of delivering crude oil, natural gas, refined products and diluent;
- disruption or failure of information technology systems and network infrastructure due to various causes, including unauthorized access or attack;
- leaks of crude oil, natural gas, refined products or diluent as a result of the malfunction of equipment or facilities;
- unexpected business interruptions;
- curtailments of operations due to severe weather, natural disasters, including hurricanes; acts of terrorism; and
- riots, strikes, lockouts or other industrial disturbances.

For example, on June 13, 2019, a building fire occurred at the Griffith Station on BP2. For additional information, please see Part II, Item 8, Note 14 - *Commitments and Contingencies* of this report.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, as well as business interruptions or shutdowns of our facilities. Any such event or unplanned shutdown could have a material adverse effect on our business, financial condition and results of operations.

Our profitability and cash flow are dependent on our ability to maintain the current volumes of crude oil, natural gas, refined products or diluent that we transport, which often depend on actions and commitments by parties beyond our control. In order to maintain the volumes transported on our assets, our customers must continually obtain new supplies of crude oil, which is expensive, particularly in offshore Gulf of Mexico.

Our profitability and cash flow are dependent on our ability to maintain the current volumes of crude oil, natural gas, refined products and diluent that we transport. A decision by BP Products not to enter into new minimum volume commitment agreements following their respective terms, or a decision by BP or another shipper to substantially reduce or cease to ship volumes of crude oil, refined products or diluent on our pipelines could cause a significant decline in our revenues. For example, we recognized approximately $2.1 million and $3.5 million of deficiency revenue under the throughput and deficiency agreements with BP Products with respect to BP2 and Diamondback, respectively, for the year ended December 31, 2019. The throughput and deficiency agreement with respect to BP2 expires in 2020 and with respect to Diamondback they expire in December 2020 and June 2021. If volumes on BP2 and Diamondback do not improve or we do not enter into new minimum volume commitment agreements after their expiration, our results will be adversely impacted. Additionally, our minimum volume commitment agreements only support our onshore operations. These agreements terminate at the expiration of their respective terms, and may be terminated earlier under certain specified circumstances, and BP Products is under no

obligation to enter into new minimum volume commitment agreements. Please read "Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements."

In addition, although our offshore assets are generally subject to term agreements or life-of-lease agreements, these agreements generally do not contain minimum volume commitments and many do not have annual cost escalation features. The crude oil and natural gas available to us under these agreements are derived from reserves produced from existing wells, and these reserves naturally decline over time. The amount of crude oil reserves underlying wells in these areas may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Accordingly, to maintain or increase the volume of crude oil transported, or throughput, on our pipelines and cash flows associated with the transportation of crude oil, our customers must continually obtain new supplies of crude oil. In addition, we will not generate revenue under our life-of-lease agreements that do not include guaranteed rates-of-return to the extent that production in the area we serve declines or is shut in.

Finding and developing new reserves, particularly in offshore Gulf of Mexico, is capital intensive, requiring large expenditures by producers for exploration and development drilling, installing production facilities and constructing pipeline extensions to reach new wells. Many economic and business factors out of our control can adversely affect the decision by any producer to explore for and develop new reserves. These factors include the prevailing market price of the commodity, the capital budgets of producers, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives, cost and availability of equipment, capital budget limitations or the lack of available capital and other matters beyond our control. Additional reserves, if discovered, may not be developed in the near future or at all. The precipitous decline in crude oil and natural gas prices beginning in late 2014 and continued volatility in commodity prices resulted in significant declines in capital expenditures by producers both on and offshore.

Additionally, the volumes of crude oil, natural gas, refined products and diluent that we transport depend on the supply and demand for crude oil, gasoline, jet fuel and other refined products in our geographic areas and other factors driving the demand for crude oil, natural gas, refined products and diluent, including competition from alternative energy sources and the impact of new and more stringent regulations and standards affecting the exploration, production and refining industries.

If new supplies of crude oil and natural gas are not obtained, or if the demand for refined products or diluent decreases significantly, there would likely be a reduction in the volumes that we transport. Any such reduction could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

If third-party pipelines, production platforms, refineries, caverns and other facilities interconnected to our pipelines become unavailable to transport, produce, refine or store crude oil, natural gas, refined products or diluent, our revenue and available cash could be adversely affected.

We depend upon third-party pipelines, production platforms, refineries, caverns and other facilities that provide delivery options to and from our pipelines. For example, Mars depends on a natural gas supply pipeline connecting to the West Delta 143 platform to power its equipment and deliver the volumes it transports to salt dome caverns in Clovelly, Louisiana. Additionally, Caesar and Cleopatra do not connect directly to onshore facilities and are dependent upon third-party pipelines for forward shipment onshore. Our onshore pipelines are dependent on interconnections with other pipelines and terminals to transport volumes to and from the Whiting Refinery.

Because we do not own these third-party pipelines, production platforms, refineries, caverns or facilities, their continuing operation is not within our control. For example, production platforms in the offshore Gulf of Mexico may be required to be shut in by the BSEE of the DOI following incidents such as loss of well control. If these or any other pipeline or terminal connection were to become unavailable for current or future volumes of crude oil, refined products or diluent due to repairs, damage to the facility, lack of capacity, shut in by regulators or any other reason, or if caverns to which we connect have cracks, leaks or leaching or require shut-in due to changes in law, our ability to operate efficiently and continue shipping crude oil, natural gas, refined products or diluent to major demand centers could be restricted, thereby reducing revenue. As an additional example, the volumes of crude oil that we transport on our BP2 system and refined products and diluent that we distribute on our River Rouge and Diamondback systems depend substantially on the economics of available crude supply for the Whiting Refinery and the economics for refined products and diluent demand in the markets that the pipelines serve. These economics are affected by numerous factors beyond our control.

Any temporary or permanent interruption at any key pipeline or terminal interconnect, at any key production platform or refinery or at caverns to which we deliver could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

Substantially all of the volumes that we transport through our onshore pipelines are dependent on the ongoing operation of the Whiting Refinery. A material decrease in the utilization of and/or demand for refined products or diluent from the Whiting Refinery could materially reduce the volumes of crude oil, refined products or diluent that we handle, which could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

Substantially all of the volumes that we transport through our onshore pipelines are directly or indirectly dependent on the ongoing operation of the Whiting Refinery. For the year ended December 31, 2019, 100% of the volumes that we transported on BP2 and River Rouge were delivered to, or originated from the Whiting Refinery and some of the diluent that Diamondback transported from BP's Black Oak Junction originated at the Whiting Refinery. Accordingly, any material decrease in the utilization of and/or demand for refined products or diluent from the Whiting Refinery could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

The utilization of the Whiting Refinery is dependent both upon: 1) the price of crude oil or other refinery feedstocks and the price of refined products and diluent and 2) availability of capacity to transport crude and product. Prices are affected by numerous factors beyond our or BP's control, including the global supply and demand for crude oil, gasoline and other refined products. The availability of capacity to transport crude and products are affected by factors beyond our or BP's control including the availability of capacity to transport Canadian heavy crude from the Alberta oil sands.

In addition to current market conditions, there are long-term factors that may impact the supply and demand of refined products and diluent in the United States. These factors include:

- increased fuel efficiency standards for vehicles;
- more stringent refined products specifications;
- new or changing renewable fuels standards;
- availability of alternative energy sources;
- potential and enacted climate change legislation; and
- increased refining capacity or decreased refining capacity utilization.

If the demand for refined products or diluent, particularly in our primary market areas, decreases significantly, or if there were a material increase in the price of crude oil supplied to the Whiting Refinery without an increase in the value of the products produced by those refineries, either temporary or permanent, which caused production of refined products or diluent to be reduced at the Whiting Refinery, there would likely be a reduction in the volumes of crude oil, refined products and diluent we transport on BP2, River Rouge and Diamondback. Any such reduction could adversely affect our financial condition, results of operations, cash flows and ability to make distributions to our unitholders.

BP is increasing the heavy crude processing capacity at the Whiting Refinery from 325 kbpd towards 350 kbpd by year-end 2020. BP expanded BP2's capacity from approximately 240 kbpd to a current capacity of 475 kbpd to accommodate this growth. This increase is expected to be implemented over the next several years through a combination of maintenance, optimization and investment projects. Should the maintenance scope, project approval or resource availability change, the Whiting Refinery's heavy crude processing capacity expansion could be delayed, which would delay any ability to seek increased volumes on BP2.

Further, the volumes of crude oil that we transport on our BP2 system and refined products and diluent that we distribute on our River Rouge and Diamondback systems depend substantially on the economics of available crude supply for the Whiting Refinery and the economics of for refined products and diluent demand in the markets that the pipelines serve. These economics are affected by numerous factors, including maintenance at the Whiting Refinery and apportionment on the Enbridge mainline (which offers all of its capacity on an uncommitted basis), each of which can cause lower throughput on our BP2 system. Volumes are also affected by maintenance and corridor shutdowns due to tie-ins, among other things.

In addition, refineries generally schedule significant maintenance periodically, with additional, less significant maintenance experienced as needed. Maintenance at the Whiting Refinery involve numerous risks and uncertainties. These risks include delays and incurrence of additional and unforeseen costs. The maintenance allows BP to perform upgrades, overhaul and repair of process equipment and materials, during which time a portion of the Whiting Refinery will be under scheduled downtime resulting in a reduced service on our onshore pipelines and as a result, we will generate reduced revenue from the pipelines impacted by such downtime. Further, due to our lack of diversification in assets and geographic location, an adverse development at the Whiting Refinery could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

We are dependent on BP for a substantial majority of the crude oil, natural gas, refined products and diluent that we transport. If BP changes its business strategy, is unable for any reason, including financial or other limitations, to satisfy its obligations under our commercial agreements or significantly reduces the volumes transported through our pipelines, our revenue would decline and our financial condition, results of operations, cash flows, and ability to make distributions to our unitholders would be materially and adversely affected.

We are dependent on BP for a substantial majority of the crude oil, natural gas, refined products and diluent that we transport. Total revenue from BP represented 97.6%, 97.6% and 98.0% of our revenues for the years ended December 31, 2019, 2018 and 2017, respectively. BP is also a material customer of Mars, Ursa, KM Phoenix and each of the Mardi Gras Joint Ventures. BP's volumes represented approximately 95.1%, 94.9% and 95.3% of the aggregate total volumes transported on the Wholly Owned Assets for the years ended December 31, 2019, 2018 and 2017, respectively. BP's volumes represented approximately 50.3% of the aggregate total pipeline volumes transported on the Wholly Owned Assets, Mars, Ursa and the Mardi Gras Joint Ventures combined for the year ended December 31, 2019. It is likely that we will continue to derive a significant portion of our revenue from BP. Therefore, any event, whether in our area of operations or otherwise, that adversely affects BP's production, financial condition, leverage, results of operations or cash flows may adversely affect our ability to sustain or increase cash distributions to our unitholders. Accordingly, we are indirectly subject to the business risks of BP, some of which are the following:

- the volatility of natural gas, NGL and oil prices, which could have a negative effect on the value of BP's oil and natural gas properties, its drilling programs or its ability to finance its operations;
- the availability of capital on an economic basis to fund BP's exploration and development activities;
- BP's ability to replace reserves, sustain production and begin production on certain leases that may otherwise expire;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production;

BP's drilling and operating risks, including potential environmental liabilities;

- transportation capacity constraints and interruptions;

adverse effects of governmental and environmental regulation; and

- losses from pending or future litigation.

Additionally, BP may suffer a decrease in production volumes in the areas serviced by us and is not obligated to use our services with respect to volumes of crude oil, refined products or diluent in excess of the minimum volume commitments under its commercial agreements with us. Please read "Business-Our Commercial Agreements with BP-Minimum Volume Commitment Agreements." The loss of a significant portion of the volumes supplied or shipped by BP would result in a material decline in our revenues and our cash available for distribution. For example, we recognized approximately $5.6 million of deficiency revenue under the throughput and deficiency agreements with BP Products with respect to BP2 and Diamondback for the year ended December 31, 2019. Our throughput and deficiency agreement with BP2 will expire December 31, 2020, and our throughput and deficiency agreements with Diamondback will expire December 31, 2020 and June 30, 2021. If volumes on BP2 and Diamondback do not improve or we do not enter into new minimum volume commitment agreements after their expiration, our results will be adversely impacted. In particular, BP Pipelines owns the BP1 pipeline, which also delivers crude oil from Cushing, Oklahoma to the Whiting Refinery. The capacity of BP1, when combined with BP2's 475 kbpd current capacity significantly exceeds Whiting Refinery's nameplate capacity of 430 kbpd. BP Products could choose to ship volumes to Whiting Refinery on BP1 instead of BP2, resulting in a material decline in volumes on BP2. In addition, BP may determine in the future that drilling activity in other areas of operation is strategically more attractive. A shift in our customers' focus away from our areas of operation could result in reduced throughput on our systems and a material decline in our revenues. For example, a further decline in production at the Whiting Refinery could materially reduce the volume of refined products transported on River Rouge. If such declines were to occur or continue during a time at which we did not have a commercial agreement with respect to BP2, Diamondback and River Rouge requiring BP to pay us a fee upon failing to satisfy minimum volume commitments, such a decline could result in a significant reduction in revenues that could have a material adverse effect on our results of operations.

Hurricanes and other severe weather conditions, natural disasters or other adverse events or conditions could damage our pipeline systems or disrupt the operations of our customers, which could adversely affect our operations and financial condition.

The operations of Mars, Ursa, Caesar, Proteus and Endymion, our offshore crude oil pipeline systems, and Cleopatra, our offshore natural gas pipeline, could be impacted by severe weather conditions or natural disasters, including hurricanes, or other adverse events or conditions. During the third quarter of 2019, the operations of Caesar, Cleopatra and Ursa were disrupted by Hurricane Barry. The gross impact was approximately 100,000 barrels of oil equivalent per day and approximately $2 million to our cash available for distribution. Any such future events may be material and may cause a serious business disruption or serious damage to our pipeline systems which could affect such systems' ability to transport crude oil and natural gas.

Additionally, such adverse events or conditions could impact our customers, and they may be unable to utilize our pipeline systems. The susceptibility of our assets to storm damage could be aggravated by wetland and barrier island erosion. In addition, neither we nor the entities in which we own an interest that own these offshore pipeline systems carry named windstorm insurance for any of our offshore pipeline systems. Weather-related risks could have a material adverse effect on our ability to continue operations and on our financial condition, results of operations and cash flows.

Our crude oil transportation operations are dependent upon demand for crude oil by refiners, primarily in the Midwest and Gulf Coast.

Any decrease in this demand for crude oil by those refineries or connecting carriers to which we deliver could adversely affect our cash flows. Those refineries', including the Whiting Refinery's, demand for crude oil also is dependent on the competition from other refineries, the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, government regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand for our services.

We face intense competition to obtain crude oil, natural gas and refined products volumes.

Our competitors include integrated, large and small independent energy companies who vary widely in size, financial resources and experience. Some of these competitors have capital resources that are greater than ours and control substantially greater supplies of crude oil, natural gas, refined products and diluent.

Even if reserves exist or refined products and diluent are produced in the areas accessed by our facilities, we may not be chosen by the shippers to transport, store or otherwise handle any of these crude oil and natural gas reserves, refined products and diluent. We compete with others for any such volumes on the basis of many factors, including:

- geographic proximity to the production and/or refineries;
- costs of connection;
- available capacity;
- rates;
- logistical efficiency in all of our operations;
- customer relationships; and
- access to markets.

If we are unable to compete effectively for transportation of crude oil, natural gas, refined products or diluent, there would likely be a reduction in the volumes that we transport. Any such reduction could have a material adverse effect on our business, results of operations, financial condition or cash flows, including our ability to make distributions.

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our assets are either self-insured or insured with third parties for certain property damage, business interruption and third-party liabilities, and such coverage includes sudden and accidental pollution liabilities. We are insured under certain of BP's corporate insurance policies and losses would be subject to the shared deductibles and limits under those policies.

All of the insurance policies relating to our assets and operations are subject to policy limits. We and the entities in which we own an interest do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Changes in the insurance markets subsequent to the September 11, 2001 terrorist attacks and Hurricanes Katrina, Rita, Gustav, Ike and Harvey have made it more difficult and more expensive to obtain certain types of coverage, and we have elected to self-insure portions of our asset portfolio or insure with third parties. For example, neither we nor the entities in which we own an interest that own our offshore pipeline systems carry named windstorm insurance for any of the offshore pipeline systems. Significant uninsured losses could have a material adverse effect on our business, financial condition and results of operation which could put pressure on our liquidity and cash flows.

We are exposed to the credit risks, and certain other risks, of our customers, and any material nonpayment or nonperformance by our customers could reduce our ability to make distributions to our unitholders.

We are subject to the risks of loss resulting from nonpayment or nonperformance by our customers. If any of our most significant customers default on their obligations to us, our financial results could be adversely affected. Our customers may be highly leveraged and subject to their own operating and regulatory risks. For certain of our pipelines, we also may have a limited pool of potential customers and may be unable to replace any customers who default on their obligations to us.

Therefore, any material nonpayment or nonperformance by our customers could reduce our ability to make distributions to our unitholders.

Any expansion of existing assets or construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our operations and financial condition.

In order to optimize our existing asset base, we intend to evaluate and capitalize on organic opportunities for expansion projects in order to increase revenue on our assets. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost.

We also intend to evaluate and may from time to time expand our existing pipelines, such as by adding horsepower, pump stations or new connections. Any such expansion projects will involve numerous regulatory, environmental, political and legal uncertainties, most of which are beyond our control. The process for obtaining environmental permits has the potential to delay any such expansion projects. In addition, the environmental reviews, permits and other approvals that may be required for such expansion projects may be subject to challenge by third parties which can further delay commencing construction.

Moreover, we may not receive sufficient long-term contractual commitments or spot shipments from customers to provide the revenue needed to support projects, and we may be unable to negotiate acceptable interconnection agreements with third-party pipelines to provide destinations for increased throughput. Even if we receive such commitments or spot shipments or make such interconnections, we may not realize an increase in revenue for an extended period of time.

We do not own all of the land on which our pipelines are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines are located, and we are, therefore, subject to the possibility of more onerous terms and increased costs to retain necessary land use if we do not have valid leases, licenses or rights-of-way ("ROWs") or if such leases, licenses or rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies, and some of our agreements may grant us those rights for only a specific period of time. Our failure to have or loss of any of these rights, through our inability to renew leases, ROW contracts or otherwise, or inability to obtain leases, licenses or ROWs at reasonable costs could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our interstate and offshore pipeline operations are subject to pipeline safety regulations administered by the PHMSA of the DOT. These laws and regulations require us to comply with a significant set of requirements for the design, construction, operation, maintenance, inspection and management of our crude oil, natural gas, refined products and diluent pipeline systems.

These requirements are subject to change over time as a result of new pipeline safety laws and additional regulatory actions. For example, in June 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 was adopted, extending PHMSA's statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain regulatory actions required under the 2011 Pipeline Safety Act. To date, PHMSA has completed 47 of approximately 62 rulemaking mandates imposed under the 2016 and 2011 Pipeline Safety Acts. For example, PHMSA finalized new pipeline safety rules for hazardous liquids and gas transmission pipelines in October 2019. The Safety of Hazardous Liquids Pipelines final rule addressed topics such as: inspections of onshore and offshore pipelines following extreme weather events and natural disasters, periodic assessment of pipelines not currently subject to integrity management, expanded use of leak detection systems, increased use of in-line inspection tools, and other requirements. The Safety of Gas Transmission Pipelines final rule addressed topics such as: maximum allowable operating pressure, expansion of integrity management requirements to previously non-regulated pipelines, and other requirements. Additional rulemakings relating to pipeline safety are expected to be issued in 2020. Although no significant new requirements have been identified with respect to the recent rulemakings, these and any future changes in existing laws and regulations could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial condition. Our actual compliance implementation costs may also be affected by industry-wide demand for the associated contractors and service providers.

Pipeline failures or failures to comply with applicable regulations could result in shut-downs, capacity constraints or operational limitations to our pipelines. Failure to comply with applicable PHMSA regulations can also result in significant

fines and penalties. PHMSA has the power to assess penalties of up to $213,268 per violation per day of violation, and up to $2,186,465 for a series of related violations. These amounts, moreover, are subject to future inflation adjustments.

Should any of these risks materialize, they could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Compliance with and changes in environmental, health and safety laws and regulations has a cost impact on our business, and failure to comply with such laws and regulations could have an impact on our assets, costs, revenue generation and growth opportunities. In addition, our customers are also subject to environmental laws and regulations, and any changes in these laws and regulations could result in significant added costs to comply with such requirements and delays or curtailment in pursuing production activities, which could reduce demand for our services. Changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could also impact us by adversely affecting the demand for our customers' products.

Our operations are subject to extensive environmental, worker health and safety, and pipeline safety laws and regulations, including those relating to the discharge and remediation of materials in the environment, waste management, natural resource protection and preservation, pollution prevention, pipeline integrity and other safety-related regulations and characteristics and composition of fuels. Numerous governmental authorities, such as the EPA, PHMSA, BSEE, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater, as well as releases to the Gulf of Mexico from our offshore pipelines. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly owned or operated by us regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. There can be no certainty that our operating management system, or other policies and procedures will adequately identify all process safety, personal safety and environmental risks or that all our operating activities will be conducted in conformance with these systems.

Failure to comply with these laws, regulations and permits may result in joint and several or strict liability or the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and/or the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which our pipeline systems pass, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws and regulations or for remediation costs, personal injury or property damage. In addition, we may experience a delay in obtaining or be unable to obtain required permits or approvals for projects related to our pipeline systems, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues, which in turn could affect our business, financial condition, results of operations, cash flows and ability to make cash distributions. As new environmental laws and regulations are enacted, the level of expenditures required for environmental matters could increase. Current and future legislative action and regulatory initiatives could result in changes to operating permits, material changes in operations, increased capital expenditures and operating costs, increased costs of the goods we transport, and decreased demand for products we handle that cannot be assessed with certainty at this time. We may be required to make expenditures to modify operations or install pollution control equipment or release prevention and containment systems that could materially and adversely affect our business, financial condition, results of operations and liquidity if these expenditures, as with all costs, are not ultimately reflected in the tariffs and other fees we receive for our services.

Our customers are also subject to environmental laws and regulations that affect their businesses, and changes in these laws or regulations could materially adversely affect their businesses or prospects. In addition, in response to concerns related to climate change, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, promoting divestment of fossil fuel equities and pressuring leaders to limit funding to companies engaged in the extraction of fossil fuels. For example, officials in New York state and New York City have announced their intent to divest the state and city pension funds' holding in fossil fuel companies, and the World Bank has announced that it will no longer finance upstream oil and gas after 2019, except in "exceptional circumstances". Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our customers' business activities, operations and cost of access to capital, which, in turn, could adversely impact their ability to meet their obligations to us. Any changes in laws, regulations, policies, obligations or access to capital that impose significant costs, liabilities or capital restraints on our customers, that result in delays, curtailments or cancellations of their projects, or that reduce demand for their products, could reduce their demand for our services and materially adversely affect our results of operations, financial position or cash flows.

We cannot predict the potential impact of changes to climate change legislation and regulations to address GHG emissions in the United States or of any climate-related litigation on our future consolidated financial condition, results of operations or cash flows, however changes in laws, regulations, policies and obligations relating to climate change, including carbon pricing, could impact our assets, costs, revenue generation and growth opportunities.

Subsidence and erosion could damage our pipelines, particularly along the Gulf Coast and offshore and the facilities that serve our customers, which could adversely affect our operations and financial condition.

Our pipeline operations along the Gulf Coast and offshore could be impacted by subsidence and erosion. Subsidence issues are also a concern for our Midwestern pipelines at major river crossings. Subsidence and erosion could cause serious damage to our pipelines, which could affect our ability to provide transportation services or result in leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water, groundwater, or to the U.S. Gulf of Mexico, which could result in liability, remedial obligations, and/or otherwise have a negative impact on continued operations. Additionally, such subsidence and erosion processes could impact our customers who operate along the Gulf Coast, and they may be unable to utilize our services. Subsidence and erosion could also expose our operations to increased risks associated with severe weather conditions and other adverse events and conditions, such as hurricanes and flooding. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure. Such costs could adversely affect our business, financial condition, results of operation or cash flows. Moreover, local governments and landowners have recently filed several lawsuits in Louisiana against energy companies, alleging that their operations contributed to increased coastal erosion and seeking substantial damages.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any necessary pipeline repair or preventative or remedial measures.

PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines, with enhanced measures required for pipelines located where a leak or rupture could harm a HCA or moderate consequence area ("MCA"). The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could affect an HCA or MCA;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The BSEE has adopted similar pipeline safety and integrity management requirements related to the design, construction, and operation of offshore pipelines under DOI's jurisdiction. At this time, we cannot predict the ultimate cost to maintain compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity inspection and testing. We will continue our pipeline integrity inspection and testing programs to assess and maintain the integrity of our pipelines. The results of these inspections and tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines. These expenditures could have a material adverse effect on our results of operations or financial condition. Moreover, changes to pipeline safety laws over time may trigger future regulatory actions, which could lead to our incurring increased operating costs that could also be significant and have material adverse effects on our result of operations or financial condition.

We may be unable to obtain or renew permits necessary for our operations or for growth and expansion projects, which could inhibit our ability to do business.

Our facilities require a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. In addition, we implement maintenance, growth and expansion projects as necessary to pursue business opportunities, and these projects often require similar permits, licenses and approvals. These permits, licenses, approval limits and standards may require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. In some instances, for construction permits, extensive environmental assessments or impact analyses must be completed before a permit can be obtained, which has the potential to result in additional operational delays. Failure to obtain required permits or noncompliance or incomplete documentation of our compliance status with any permits that are obtained may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations and on our financial condition, results of operations and cash flows.

Our asset inspection, maintenance or repair costs may increase in the future. In addition, there could be service interruptions due to unforeseen events or conditions or increased downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Our pipelines were constructed over several decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have varied over time. Depending on the condition and results of inspections, some assets will require additional maintenance, which could result in increased expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

We maintain an integrity management program to monitor the condition of our assets. As there are many factors that are under our influence and others that are not, it is difficult to predict future expenditures related to integrity management inspections and repairs. Additionally, there could be service interruptions associated with these repairs or other unforeseen events. Similarly, laws and regulations may change which could also lead to increased integrity management expenditures. Any increase in these expenditures could adversely affect our results of operations, financial position, or cash flows which in turn could impact our ability to make cash distributions to our unitholders.

The tariff rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our revenue and our ability to make distributions to our unitholders.

We provide both interstate and intrastate transportation services for refined products, diluent and crude oil. Our regulated pipelines are required to provide reasonable service to any shipper similarly situated to an existing shipper that requests transportation services on our pipelines.

Mars, BP2, Diamondback, and River Rouge pipelines provide interstate transportation services that are subject to regulation by FERC under the ICA, and Endymion could be subject to intrastate or FERC jurisdiction under certain circumstances in the future. FERC uses prescribed rate methodologies for developing and changing regulated rates for interstate pipelines, including price-indexing with inflation. The indexing method allows a pipeline to increase its rates based on a percentage change in the PPI-FG plus a FERC determined adder and is not based on pipeline-specific costs. If the index falls, we will be required to reduce our rates that are based on the FERC's price indexing methodology if they exceed the new maximum available ceiling rate. However, changes in the index might not be large enough to fully reflect actual increases in our costs. If FERC changes its rate-making methodologies, the new methodologies may result in tariffs that generate lower revenues and cash flows. The FERC's rate-making methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs. Any of the foregoing could adversely affect our revenues and cash flows. Effective January 2018, the Tax Cuts and Jobs Act changed several provisions of the federal tax code, including a reduction in the maximum corporate tax rate. The Revised Policy Statement requires the reduced maximum corporate tax rate allowance that can be reflected in initial oil cost-of-service rates, future cost-of-service rate changes, and in future filings of Page 700 of FERC Form No. 6. FERC will consider the information provided by pipelines in Page 700 of FERC Form No. 6 in its 2020 five-year review of the oil pipeline index level. Please read "Business-FERC and Common Carrier Regulations." Furthermore, on October 20, 2016, FERC issued an ANOPR regarding Revisions to Indexing Policies and Page 700 of FERC Form No. 6. Effective February 21, 2020, FERC withdrew the ANOPR.

Shippers may protest (and FERC may investigate) the lawfulness of existing, new or changed tariff rates. FERC can suspend new or changed tariff rates for up to seven months and can allow new rates to be implemented subject to refund of amounts collected in excess of the rate ultimately found to be just and reasonable. Shippers may also file complaints that existing rates are unjust and unreasonable. If FERC finds a rate to be unjust and unreasonable, it may order payment of reparations for up to two years prior to the filing of a complaint or investigation, and FERC may prescribe new rates prospectively. We may at any time also be required to respond to governmental requests for information, including compliance audits conducted by FERC.

Whether a pipeline provides service in interstate commerce or intrastate commerce, or is otherwise non-FERC-jurisdictional, is highly fact-dependent and determined on a case-by-case basis. We cannot provide assurance that FERC will not at some point assert jurisdiction over some or all currently non-FERC jurisdictional transportation services that we provide based on a determination that a pipeline or pipelines are providing transportation service in interstate commerce and not exclusively intrastate commerce or otherwise non-FERC-jurisdictional. If the FERC were successful in asserting jurisdiction, its ratemaking methodologies may subject us to potentially burdensome and expensive operational, reporting and other requirements.

Caesar provides transportation services that are subject to regulation by FERC pursuant to OCSLA, which includes a duty to provide open and non-discriminatory access on the Caesar facilities. Shippers or other entities may protest the terms or conditions of Caesar's transportation services as being inconsistent with the open access and non-discrimination requirements

of OCSLA. If FERC grants such a protest, Caesar may be required to modify the terms or conditions of Caesar's transportation services, which could adversely affect our revenue and our ability to make distributions to our unitholders.

Gas-gathering facilities are generally exempt from FERC's jurisdiction under the NGA. Determinations as to whether a gas pipeline provides FERC-regulated transmission service or non-jurisdictional gathering service have been subject to substantial litigation over time. If FERC were to determine that the services provided by our gas-gathering facilities are not exempt from FERC regulation, then FERC could exercise authority over the rates and terms and conditions of service. Regulation by FERC could increase our operating costs, and could negatively affect our results of operations and financial condition.

State agencies may also regulate the rates, terms and conditions of service for our pipelines offering intrastate transportation services, and such agencies could limit our ability to increase our rates or order us to reduce our rates and pay refunds to shippers. State agencies can also regulate whether a service may be provided or cancelled. If a state agency were to assert jurisdiction over services that are currently non-jurisdictional, we could be subject to these potentially burdensome and expensive requirements.

The FERC and most state agencies generally support light-handed regulation of common carrier refined products, diluent, and crude oil pipelines and have generally not investigated the rates, terms and conditions of service of pipelines in the absence of shipper complaints and may resolve complaints informally. Louisiana's Public Service Commission has a more stringent review of rate increases and may prohibit or limit future rate increases for intrastate movements regulated by Louisiana.

Accepted tariffs do not, however, prevent any other new or prospective shipper, FERC or a state agency from challenging our tariff rates or our terms and conditions of service. Shippers can contest existing rates or terms at any time but must provide the burden of proof supporting their complaint of rates, rules, or discriminatory behavior.

Further, the FERC's and state agencies' actions are subject to court challenge, which may have broader implications for other regulated pipelines. FERC's indexing methodology is applicable to existing rates, with the exclusion of market-based rates. FERC's indexing methodology is subject to review every five years. During the five-year period commencing July 1, 2016 and ending June 30, 2021, common carriers charging indexed rates are permitted to adjust their indexed ceilings annually by PPI-FG plus 1.23%. Many existing pipelines, including BP2, Diamondback, and Mars, utilize the FERC oil index to change transportation rates annually every July 1.

On March 15, 2018, in a set of related issuances, FERC addressed treatment of federal income tax allowances in regulated entity rates. To the extent a regulated entity is permitted to include an income tax allowance in its cost-of-service, FERC directed entities to calculate the income tax allowance at the reduced 21% maximum corporate tax rate established by the Tax Cuts and Jobs Act. FERC also issued the Revised Policy Statement stating that it will no longer permit MLPs to recover an income tax allowance in their cost-of-service rates. FERC requires oil and refined products pipelines subject to FERC jurisdiction to reflect the impacts to their cost of service from the Revised Policy Statement and the Tax Cuts and Jobs Act on the Page 700 of FERC Form No. 6. This information will be used by FERC in its next five-year review of the oil pipeline index to generate the index level to be effective July 1, 2021, thereby including the effect of the Revised Policy Statement and the Tax Cuts and Jobs Act in the determination of indexed rates prospectively, effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act may impact our revenues associated with any transportation services we may provide pursuant to both cost-of-service based rates in the future and indexed rates.

A successful challenge to any of our rates, or any changes to FERC's approved rate or index methodologies, could adversely affect our revenue and our ability to make distributions to our unitholders. Similarly, if state agencies in the states in which we offer intrastate transportation services change their policies or aggressively regulate our rates or terms and conditions of service, it could also adversely affect our revenue and our ability to make distributions to our unitholders.

Our fixed loss allowance exposes us to commodity prices.

Some of our long-term transportation agreements and tariffs for crude oil shipments include an FLA, including certain agreements and tariffs on BP2, Mars and Endymion.

On Mars and Endymion, we collect FLA to reduce our exposure to differences in crude oil measurement between origin and destination meters, which can fluctuate. With respect to Mars, this arrangement exposes us to risk of financial loss in some circumstances when the crude oil is received from a third party and there is a difference between our measurement and theirs; it is not always possible for us to completely mitigate the measurement differential. If the measurement differential exceeds the

fixed loss allowance, the pipeline must make the customer whole for the difference in measured crude oil. Additionally, on our Mars and Endymion pipelines, we take title to any excess product that we transport when product losses are within the allowed levels, and we sell that product several times per year at prevailing market prices. This allowance oil revenue is subject to more volatility than transportation revenue, as it is directly dependent on our measurement capability and prevailing commodity prices at the time of sale.

On BP2, we do not take physical possession of the allowance oil as a result of our services, due to lack of storage associated with this asset. Accordingly, on BP2, we settle allowance oil receivables monthly at prices reflective of the current market conditions. Allowance oil revenue accounted for 8.0%, 7.5%, and 8.0% of our total revenue in 2019, 2018 and 2017, respectively.

If we lose any of our key personnel, our ability to manage our business and continue our growth could be negatively impacted.

We depend on our senior management team and key technical personnel. If their services are unavailable to us for any reason, we may be required to hire other personnel to manage and operate our company and to develop our products and technology. We cannot assure you that we would be able to locate or employ such qualified personnel on acceptable terms or at all.

Terrorist or cyber-attacks and threats, or escalation of military activity in response to these attacks, could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, or escalation of military activity in response to these attacks, may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. A breach or failure of our digital infrastructure due to intentional actions such as cyber-attacks, negligence or other reasons, could seriously disrupt our operations and could result in the loss or misuse of data or sensitive information, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches and potential legal liability.

Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future terrorist or cyber-attacks than other targets in the United States. We do not maintain specialized insurance for possible liability or loss resulting from a cyber-attack on our assets that may shut down all or part of our business. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital including our ability to repay or refinance debt. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Potential disruption to our business and operations could occur if we do not address an incident effectively.

Our business and operating activities could be disrupted if we do not respond, or are perceived not to respond, in an appropriate manner to any major crisis or if we are not able to restore or replace critical operational capacity.

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

We entered into a revolving credit facility in connection with our IPO. Our revolving credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances; and
- incur certain liens or permit them to exist.

Our revolving credit facility contains covenants requiring us to maintain certain financial ratios. The provisions of our revolving credit facility may affect our ability to obtain future financing and to pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations-Capital Resources and Liquidity."

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures (including building additional gathering pipelines needed for required connections and building additional centralized gathering facilities pursuant to our gathering agreements) or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt depends upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, investments or capital expenditures, selling assets or issuing equity. We may not be able to effect any of these actions on satisfactory terms or at all.

Increases in interest rates could adversely impact the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on the price of our common units, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

The lack of diversification of our assets and geographic locations could adversely affect our ability to make distributions to our common unitholders.

We rely on revenue generated from our pipelines, which are primarily located offshore Louisiana and onshore in the mid-western U.S. Due to our lack of diversification in assets and geographic location, an adverse development in our businesses or areas of operations, including adverse developments due to catastrophic events, weather, regulatory action and decreases in demand for crude oil, natural gas, refined products and diluent, could have a significantly greater impact on our results of operations and cash available for distribution to our common unitholders than if we maintained more diverse assets and locations.

If we are deemed an "investment company" under the Investment Company Act of 1940, it could have a material adverse effect on our business and the price of our common units.

Our assets include partial ownership interests in Mars, Ursa, KM Phoenix and Mardi Gras, as well as wholly owned pipelines. If a sufficient amount of our assets, or other assets acquired in the future, are deemed to be "investment securities" within the meaning of the Investment Company Act of 1940, we may have to register as an "investment company" under the Investment Company Act, claim an exemption, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights. Registering as an "investment company" could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage, and require us to add additional directors who are independent of us or our affiliates. The occurrence of some of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

Risks Inherent in an Investment in Us

BP Holdco owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including BP Pipelines, may have conflicts of interest with us and have limited duties to us, and they may favor their own interests to our detriment and that of our unitholders.

BP Holdco, a wholly owned subsidiary of our sponsor, BP Pipelines, owns and controls our general partner and appoints all of the directors of our general partner. Although our general partner has a duty to manage us in a manner that it believes is not opposed to our interest, the executive officers and certain of the directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to BP Holdco. In addition, all of our executive officers and certain of our directors have a fiduciary duty to BP Pipelines or its affiliates due to their position as officers and directors of BP Pipelines or its affiliates. Therefore, conflicts of interest may arise between BP Holdco, BP Pipelines or any of their respective affiliates, including our general partner, on the one hand, and us or any of our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as BP Holdco and BP Pipelines, in exercising certain rights under our partnership agreement;
- neither our partnership agreement nor any other agreement requires BP Holdco or its affiliates (including BP Pipelines) to pursue a business strategy that favors us;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties and limits our general partner's liabilities, which restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- disputes may arise under agreements pursuant to which BP Pipelines and its affiliates are our customers;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any cash expenditure and whether an expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash from operating surplus that is distributed to our unitholders which, in turn, may affect the ability of the subordinated units to convert;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period;
- our partnership agreement permits us to distribute up to $110.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or the incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our general partner controls the enforcement of obligations that it and its affiliates owe to us;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or the unitholders. This election may result in lower distributions to the common unitholders in certain situations.

In addition, we may compete directly with BP Pipelines and entities in which it has an interest for acquisition opportunities and potentially will compete with these entities for new business or extensions of the existing services provided by us. Please read "BP Pipelines and other affiliates of our general partner may compete with us."

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we intend to distribute quarterly at least $0.2625 per unit on all of our units to the extent we have sufficient cash after the establishment of cash reserves and the payment of our expenses, including payments to our general partner and its affiliates. However, the board of directors of our general partner may change such policy at any time at its discretion and could elect not to pay distributions for one or more quarters.

In addition, our partnership agreement does not require us to pay any distributions at all. Accordingly, investors are cautioned not to place undue reliance on the permanence of such a policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the board of directors of our general partner, whose interests may differ from those of our common unitholders. Our general partner has limited duties to our unitholders, which may permit it to favor its own interests or the interests of BP Holdco or BP Pipelines or their affiliates to the detriment of our common unitholders.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner, and our partnership agreement provides that our general partner may limit its liability without breaching our general partner's duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

We expect to distribute a significant portion of our cash available for distribution to our partners, which could limit our ability to grow and make acquisitions.

We plan to distribute most of our cash available for distribution, which may cause our growth to proceed at a slower pace than that of businesses that reinvest their cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the cash that we have available to distribute to our unitholders.

Our general partner will be required to deduct Estimated Total Maintenance Spend from our operating surplus, which may result in less cash available for distribution to unitholders from operating surplus than if actual Total Maintenance Spend (total maintenance expenses and maintenance capital expenditures) were deducted.

We track Total Maintenance Spend on an ongoing basis, which represents the sum of maintenance expenses and maintenance capital expenditures in any given financial reporting period. Collectively these expenditures are made to maintain over the near and long term our operating capacity and operating income. Our partnership agreement requires our general partner to deduct Estimated Total Maintenance Spend, rather than actual Total Maintenance Spend, from operating surplus in determining cash available for distribution from operating surplus.

The amount of Estimated Total Maintenance Spend deducted from operating surplus will be subject to review and change by our general partner's board of directors at least once a year. Our partnership agreement does not cap the amount of Estimated Total Maintenance Spend that our general partner may estimate, and such estimate is intended to represent the average annual Total Maintenance Spend on a three-year basis, as fluctuations in actual amounts can vary substantially in any given year. In years when our Estimated Total Maintenance Spend is higher than actual Total Maintenance Spend, the amount of cash available for distribution to unitholders from operating surplus will be lower than if actual Total Maintenance Spend had been deducted from operating surplus. On the other hand, if our general partner underestimates the appropriate level of Estimated Total Maintenance Spend, we will have more cash available for distribution from operating surplus in the short term but will have less cash available for distribution from operating surplus in future periods when we have to increase our Estimated Total Maintenance Spend to account for the previous underestimation.